REPORT OF THE STATE COMMISSION PRACTICE & REGULATION COMMITTEE

Although this Committee has been active for almost five years, the following represents its inaugural report to the membership. Here, the Committee has endeavored to summarize the significant state legislative enactments and administrative decisions affecting the electric utility sector from January 2008 through May 2009, dividing the country into five regions.*

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I. NEW ENGLAND REGION

Five of New England's six states (excepting Vermont) restructured their electric industries and initiated the development of competitive retail electric markets in the late 1990s. As much as forty-five percent of state-wide load has been captured by competitive suppliers, virtually all of which is industrial and large commercial load.[1] During the period reviewed (i.e. 2008 to mid-2009), these five states obtained electric supply for retail sales under competitive auctions employing the wholesale market, and pursued various statutorily established planning processes (i.e. Integrated Resource Planning) and programs (such as state-wide DSM and energy efficiency) to minimize both current and future electricity costs. Through both legislation and Regulator action development of needed and cost-effective renewable energy and transmission was encouraged.

A. Connecticut

On February 18, 2009, the Department of Public Utility Control (DPUC) approved with modifications[2] the resource assessment and procurement plans that had been submitted by the state's electric distribution companies (EDCs) and reviewed by the Connecticut Energy Advisory Board (CEAB). The DPUC agreed with the EDCs and CEAB that no additional generation resources should be procured at this time, beyond those prescribed in 2007 legislation (2007 Energy Act), because forecasts indicated that Connecticut will not have a

1. Statistics on sources of electric supply are generally available on State PUC websites either separately or in various filed statistical reports. *See* National Association of Regulatory Utility Commissioners, http://www.naruc.org (last visited Oct. 10, 2009) (through which access to individual PUC websites may be obtained).

2. Review of the Integrated Resource Plan, Docket No. 08-07-01 (DPUC 2009).

shortage of energy or capacity during the statutorily defined planning horizon. Based on that forecast, the DPUC did not approve the EDCs' and CEAB's recommendation to procure hundreds of millions of dollars of new conservation and demand response resources over the next ten years. In its order, the DPUC announced it will review future resource assessment and procurement plans in two phases. First, it will examine whether Connecticut has any current or forecasted reliability needs. Then, it will examine the costs and benefits associated with each procurement option. Pursuant to the 2007 Energy Act,[3] United Illuminating (UI) and Connecticut Light & Power (CL&P) filed plans to build peaking generation on a regulated cost-of-service basis. The DPUC reviewed those proposals in a contested case, and found that it was in the best interest of ratepayers to approve a portfolio of three peaking generators totaling approximately 678 megawatts of summer peaking capacity.[4] The DPUC determined that such a portfolio would be among the highest in total benefits, and would provide ratepayers with the maximum benefit relative to cost. The DPUC rejected nine project proposals that would have put ratepayers at risk for incurring unnecessary costs for peaking generation facilities that may not provide benefits.

The 2007 Energy Act had also directed the DPUC to order decoupling of an electric distribution company's revenues from the company's sales, through rate design changes or a sales adjustment clause or both, at the time of the company's next rate proceeding, and to determine in that rate case whether any adjustment to the company's authorized return on equity should be made as a result of the decoupling.[5] These decoupling orders were aimed at reducing or eliminating adverse impacts on electric distribution companies due to lower sales revenues resulting from the implementation of energy efficiency and conservation programs. The DPUC approved decoupling in January 2008 for CL&P[6] and in September 2008 for UI.[7] On June 12, 2008, Public Act No. 08-168, An Act Concerning Energy Scarcity and Security, Renewable and Clean Energy and a State Solar Strategy, became law. The Act mandates three studies of Connecticut's energy future:

(1) a task force will undertake scenario planning for long-term petroleum and natural gas scarcity, steep price increases and supply disruptions; (2)

the Office of Policy and Management will conduct a petroleum sensitivity study of state agencies; and (3) the Renewable Energy Investment Board will study how other states promote and increase the use and supply of renewable energy and clean energy, including an examination of funding for and the mission of renewable energy and clean energy funds and departments.

B. Maine

As part of an on-going investigation into whether Maine's interests are best served by continued participation in ISO New England Inc. (ISO-NE), the Maine

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3. An Act Implementing the Provisions of the Budget Concerning Gen. Gov't, 2007 Conn. Acts 07-4 (Spec. Sess.).

4. Review of Peaking Generation Projects, Docket No. 08-01-01 (DPUC 2008).

5. An Act Implementing the Provisions of the Budget Concerning Gen. Gov't, 2007 Conn. Acts 07-4

6. CL&P Rate Amendment, DPUC Docket No. 03-07-02RE10 (DPUC 2008).

7. UI Rate Case, DPUC Docket No. 05-06-04RE04 (DPUC 2008).

Public Utilities Commission (MPUC) issued an order in January 2009 directing the electric utilities it regulates to seek changes to its arrangements with ISO-NE.[8] While the order found that participation in ISO-NE yielded considerable benefits, including the management of energy supply markets, a functioning forward capacity auction, and sophisticated energy dispatching and grid balancing systems, the MPUC also found that:

ISO-NE's governance structures do not sufficiently represent consumer interests;

ISO-NE's cost-allocation methodologies encourage over-reliance on transmission investment; and

ISO-NE lacks adequate barriers against transmission cost overruns for investments in regional transmission upgrades, which have been over $4 billion since 2004.

The MPUC called for several specific reforms to be addressed in negotiations.[9] Among them:

formalized consideration by ISO-NE of costs consumers bear as a consequence of its decisions, including recruiting board members with knowledge of consumer issues, and establishment of a regional consumer advocate to provide closer monitoring of ISO-NE activities;

cost allocation methodologies that do not spread 100% of approved transmission investment costs to ratepayers across the entire region;

when planning regional systems, greater consideration should be given to: (1) renewable energy goals set by the states; and (2) fuel diversification needs; and better controls on cost over-runs and greater consideration of transmission alternatives.

The case remains open, and proceedings to assess the progress of negotiations to reach these objectives will occur. Also, pursuant to a legislative mandate, the MPUC is exploring the merits of Maine utilities withdrawing from ISO-NE in favor of contracts with ISO-NE for certain market services on an "a la carte" basis.

The MPUC is considering an application concerning the Maine Power Reliability Project (MPRP), a proposal by Central Maine Power Company (CMP) to make approximately $1.5 billion in upgrades and additions to its high voltage transmission system.[10] An MPUC decision is expected soon on CMP's petition for a Certificate of Public Convenience and Necessity to construct the project, as well as an ISO-NE decision regarding CMP's intention to include all of the costs of the project in New England's regional transmission rates. In February 2009, the MPUC dismissed a petition for a Certificate of Public

8. Maine Public Utilities Commission Investigation of Maine Utilities Continued Participation in ISO-NE, MPUC Docket No. 2008-156 (MPUC 2009), *available at* http://mpuc.informe.org/easyfile/easyweb.php?func=easyweb_query.

9. *Id*.

10. Petition for Finding of Public Convenience and Necessity for the Maine Power Reliability Program Consisting of the Construction of Approximately 350 Miles of 345 kV and 115 KV Transmission Lines (MPRP), MPUC Docket No. 2008-255 (MPUC 2009), *available at* http://mpuc.informe.org/easyfile/easyweb.php?func=easyweb_query.

Convenience and Necessity for the Maine Power Connection (MPC),[11] a proposed $625 million transmission project that would have interconnected northern Maine with the transmission system dispatched by ISO-NE. The MPC would have facilitated the development of large wind power projects in northern Maine. The petition was dismissed because of technical/reliability issues with the proposed interconnection and concerns that the proposed wind projects might not be developed on time or at all.

C. Massachusetts

On July 2, 2008, Governor Patrick signed into law "An Act Relative to Green Communities," also known as the "Green Act."[12] The stated goals of this broad, new legislation are to: (1) meet at least twenty-five percent of the electric load in Massachusetts, including both capacity and energy, by the year 2020 with clean resources and demand side management; (2) meet at least twenty percent of Massachusetts' electric load by the year 2020 through new, renewable and alternative energy generation; (3) reduce the use of fossil fuel in state buildings by ten percent from 2007 levels by 2020 through the increased efficiency of both equipment and the building envelope; and (4) develop a plan to reduce total energy consumption in Massachusetts by at least ten percent by 2017 through the development and implementation of a green communities program that utilizes renewable energy, demand reduction, conservation, and energy efficiency. Under the Green Act, the capacity of wind, solar, and agricultural facilities eligible for net metering must be expanded from 60 kW to 2 MW, and a new category of net metering eligibility for neighborhoods must be added. To address the net metering requirements, on March 6, 2009, the Massachusetts Department of Public Utilities (DPU) issued an order instituting a rulemaking proceeding.[13]

On July 16, 2008, the DPU issued an order (July 16 Order) initiating a process to decouple rates from sales volume for all electric and natural gas distribution utilities in Massachusetts.[14] Decoupling will encourage utilities to help their customers reduce their energy consumption and take advantage of on-site renewable energy. The July 16 Order requires that gas and electric utilities file rate plans that separate, or decouple, their sales of electricity and gas from the revenues they need to collect in order to maintain their electricity and natural gas distribution systems. To achieve full decoupling:

Each electric and natural gas utility company must submit a rate case to the DPU and proceed through a full evidentiary hearing process, to establish rates.

Rates will be set at a level designed to recover the company's prudently incurred costs, plus an adequate return on investment.

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11. Request for Certificate of Public Convenience and Necessity to Build a 345 kV Transmission Line between Limestone, ME and Detroit, ME (the "Maine Power Connection" Project), Order of Dismissal, MPUC Docket No. 2008-256 (MPUC 2009), *available at* http://mpuc.informe.org/easyfile/easyweb.php?func=easyweb_query.

12. 2008 Mass. Acts 169.

13. Order Instituting Rulemaking, D.P.U. 08-75 (Mass. DPU 2009).

14. Investigation Into Rate Structure to Promote Efficient Deployment of Demand Resources, D.P.U. 07-50-A (Mass. DPU 2008).

Rates will be subject to review and reconciliation on an annual basis. If a company's revenues are higher than expected, the excess is returned to consumers as a credit; if revenues are lower due to demand-reduction programs and other factors, the company will be allowed to recover the difference through a rate adjustment.

Utilities are expected to file decoupled rate plans with the DPU as existing rate plans expire, for most companies, by 2012, but companies can file sooner on a voluntary basis. On May 15, 2009, National Grid filed the first revenue decoupling ratemaking plan.

D. New Hampshire

On July 7, 2008, Senate Bill 383, a law establishing a commission to develop a plan for the expansion of transmission capacity in northern regions (Transmission Commission) took effect.[15] The Transmission Commission issued a progress report on December 1, 2008, in which it recommended the following: (1) review the statute governing the Site Evaluation Committee with the intention of streamlining the consideration of transmission line construction for renewable generation facilities; (2) enact legislation authorizing an economic development body to own and operate transmission facilities; and (3) make renewable energy facilities eligible for industrial development bonds. The report also concluded that all reasonable steps are being pursued at the regional level to amend the interconnection queue process and to achieve regionalization of the costs of an upgrade to the Coos County loop, which faces considerable opposition from outside New Hampshire. Thus, the report further concluded that it is critical that project developers in New Hampshire expeditiously bring forward for consideration a detailed cost allocation proposal. The New Hampshire legislature also passed the following energy-related laws:

SB 451, authorizing rate recovery of investments in distributed energy resources, including programs and equipment for clean electric generation (5 MW or less), energy storage, energy efficiency, demand response, and load reduction and control;

HB 1628, which provides a one-time incentive payment of $3 per watt of generation capacity up to a maximum payment of $6,000 or fifty percent of system costs, whichever is less, for residential installations of renewable energy systems of less than 5 kilowatts in peak capacity;

HB 1561, establishing an energy efficiency and sustainable energy board charged with promoting and coordinating energy efficiency, demand response, and sustainable energy programs in the state; and

HB 310, which prohibits municipalities from unreasonably limiting or unreasonably hindering the performance of "small" wind systems – those with 100 kilowatts or less of peak generation capacity.

E. Rhode Island

In April 2008**,** the Rhode Island Public Utility Commission (RI PUC) determined that the Rhode Island Resource Recovery Corporation (RIRRC), a quasi-public corporation that operates the Rhode Island Central Landfill, would

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15. S.B. 383 (N.H. 2008), *available at* www.gencourt.state.nh.us/legislation/2008/SB0383.html.

qualify as a public utility or electric distribution company if it constructed and operated a "direct electrical connection" to deliver electricity from a power plant to multiple end-users in the adjacent industrial park.[16] However, the RI PUC determined that the RIRRC did not qualify as a "self-generator" because it did not own the generation (it only owned the electric output), nor did it qualify as a "co-generator" because it was not both the generator and end-user of the electric output at issue. Had the RIRRC qualified as a self-generator or as a co-generator, it would have enabled the tenants of the industrial park to avoid service charges by the local utility, National Grid. On January 17, 2008, the RI PUC approved National Grid's Demand Side Management (DSM) program. The 2008 DSM program included a number of improvements to existing DSM programs "with a focus on assisting low to moderate income residential customers [to] reduce their monthly bills through [DSM] opportunities."[17] Specifically, the Single Family Low Income Services Program was to provide qualifying low-income customers in 1-4 unit dwellings with energy efficiency services. Under the Small Business Service Program, the company proposed to reduce the customer rebate from seventy-five to seventy percent of the total installed cost of an energy efficiency measure. Under the Large Business Service Program, the company offered a two-tiered rebate for new construction projects that rewards projects that have the potential to save more energy. On April 6, 2009, the RI PUC approved further refinements to National Grid's DSM program, extending the plan to cover both gas and electric energy efficiency and increasing the level of savings.[18] In July 2008, the General Assembly amended RI General Laws §§ 39-26-2 and 39-26-6(g)-(k) as they relate to net metering and renewable generation credits resulting from net metering by eligible renewable energy resources. The amendments increased the aggregate amount of net metering allowed, increased the maximum allowable distributed generation capacity for eligible net metering systems, and allowed net-metering credits to be carried forward for a period of twelve months, at which time any remaining credits would be deposited into a new renewable energy low income fund to be created by the RI PUC.

F. Vermont

A consortium of Vermont utilities commissioned a consulting study to examine the generating alternatives that may be available to serve Vermont load. Phase 1 of this study, published on January 18, 2008, describes a burgeoning "supply gap" due to the expiration of the Vermont Yankee contract in 2012 and supply contracts with Hydro Québec over the period from 2012 to 2020.[19] That gap grows from 500 MW in 2012 to approximately 1,000 MW in 2020 (assuming demand side reductions of 300 MW). The study ranked on a

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16. In re Rhode Island Res. Recovery Corp. Petition for Declaratory Judgment, Docket No. 3565 (Apr. 21, 2008).

17. In re The Narragansett Elec. Co., d/b/a Nat'l Grid Demand Side Mgmt. Programs for 2008, Docket No. 3892, at 2 (Jan. 17, 2008).

18. In re The Narragansett Elec. Co., d/b/a National Grid Gas and Elec. Energy Efficiency Program Plans for 2009, Docket No. 4000 (Apr. 6, 2009).

19. CONCENTRIC ENERGY ADVISORS, VERMONT UTILITIES TECHNICAL AND COST ISSUES OF GENERATION ALTERNATIVES, PHASE 1 (Jan. 18, 2008).

levelized cost/MWh basis eleven distinct technologies that could be used to increase supply. Pulverized coal, combined-cycle gas and nuclear were ranked the lowest cost resources, while solar and fuel cells were ranked the highest. The Phase 2 study, issued in August 2008, concluded that renewable resources, though a desirable element of Vermont's supply mix, will need to be supplemented with a larger baseload plant or several medium-sized baseload plants, given cost, transmission constraints and energy needs in Vermont.[20] Methane, combined heat/power and wood were highlighted as technologies that had relatively low to moderate development costs and permitting risks. Solar and fuel cell resources were viewed as relatively easy to permit but expensive, while wind and hydro resources were viewed as difficult to site in Vermont. Coal and nuclear generation, though the least expensive in $/MWh, were all but ruled out in the study due to, among other concerns, the potential for numerous adverse environmental and social impacts.

In November 2008, Vermont's three largest electric utilities issued a joint request for new power supply resource proposals, with the state's two largest utilities issuing an additional request for bids to supply more energy in case Vermont Yankee is unavailable.[21] The utilities are using this opportunity to diversify their portfolios in the years ahead, expanding the pool of potential power suppliers to ensure the best power mix possible. Factors the utilities will consider include price, volatility or stability, fuel diversity, environmental attributes, the results of the state's public outreach process, and reliability. In response to their request, the utilities have received dozens of new energy sales proposals, ranging in duration from a year to two decades, and representing a wide range of electricity sources, with a mix of costs and attributes. On February 11, 2009, the Vermont Public Service Board (PSB) issued an order approving Vermont Electric Power Company's (VELCO) plans to construct the Southern Loop project, which is a $260 million transmission upgrade project designed to meet both regional and local reliability needs.[22] On May 18, 2009, the Vermont Department of Public Service authorized VELCO to use nine "off-corridor access routes" for the construction of the project. However, VELCO must also receive approval from the PSB before it can use the roads to move equipment and materials, such as electric cables and poles, into the corridor.

II. MID-ATLANTIC REGION

The six Mid-Atlantic states all have restructured their electric industry, have active competitive electric wholesale and retail markets supported by an RTO/ISO and have competitive retail natural gas markets. As much as forty-five percent of state-wide electric load has been captured by competitive suppliers, virtually all of which is industrial and commercial load.[23] The principal focus

20. ESSEX PARTNERSHIP, VERMONT UTILITIES STUDY OF NEW GENERATION ALTERNATIVES, PHASE 2 (Aug. 2008), *available at* http://www.cvps.com/AboutUs/news/FinalGenerationReport.pdf.

21. 2008 Solicitation for New Resources (2008), http:www.cvps.com/ProgramsServices/powerrfp.aspx; Contingent Need Solicitation for New Resources (2008), http://www.cvps.com/ProgramsServices/contingentrfp.aspx.

22. Vermont Public Service Board, Docket No. 7373 (Feb. 11, 2009). A copy of the order is available at: http://www.state.vt.us/psb/orders/2009/feb.htm.

23. See textual note and National Association of Regulatory Utility Commissioners, *supra* note 1.

during the Reporting Period (2008 to mid-2009) has been the continued transition to competitive electric retail markets. In most states, price caps adopted in original restructuring legislation have or will soon expire and both Regulators and Political leaders have focused on mitigating the large price increases (generally thirty to seventy percent) which growth in underlying fuel and commodity costs over the up to ten years since the caps were imposed necessitate in an uncapped market place. This effort has included adoption of revitalized integrated resource planning, improved portfolio management approaches for securing electric supply, energy efficiency and conservation programs and rate increase phase-in plans to reduce the immediate impact of the required post rate cap price increases. Several states have studied partial or full "re-regulation", but have rejected this option as unlikely to produce benefits. In addition, major effort has been devoted to developing renewable generation. This has included both on and off-shore wind generation projects, expanded programs for distributed solar photo-voltaic generation and enhanced state supported energy efficiency and DSM programs. An additional area of activity has been certification of transmission lines needed to permit increased economic and reliability based imports from western states.

A. Delaware

Rate caps adopted in Delaware's transition to competitive electric markets expired in 2006 resulting in substantial price increases to end users. In response, the State passed legislation implementing a phase-in plan, reestablishing Delaware Public Service Commission (DEL PSC) led Integrated Resource Planning and directing State Agencies to review options for the sector's future. [24] The DEL PSC implemented the legislation with a series of proceedings to establish specifics of the phase-in and to develop a state-wide IRP.[25] Several Orders have been issued since enhancing the IRP process, adopting regulations and initiating a second IRP Plan development.[26] Enhanced oversight was directed at the supply management portfolio and multiple bid auction process administered by the PSC through which electric supply is procured from the wholesale market for retail service.[27] The State has also adopted a Renewable Energy Portfolio Standard pursuant to which Delmarva has acquired 200 MW of off-shore wind power to be developed by 2015 and 460 MW of on-shore wind

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24. Electric Utility Retail Customer Supply Act of 2006, 75 Del. Laws 242 (2006); NANCY BROCKWAY, DELAWARE'S ELECTRIC FUTURE: RE-REGULATION OPTIONS AND IMPACTS (2007).

25. *See, e.g.* Delmarva Power & Light Co., 249 P.U.R.4th 342 (Del. PSC 2006); Integrated Resource Planning for the Provision of Standard Offer Supply Service By Delmarva Power & Light, No. 06-241 (Del. PSC 2006); The Provision of Standard Offer Supply to Retail Consumers in the Service Territory of Delmarva Power & Light Co., Order No. 6746, No. 04-391 (Del. PSC 2006) [hereinafter, *Order 6746*].

26. Investigation into the Adoption of Proposed Rules and Regulations to Accomplish Integrated Resource Planning for the Provision of Standard Offer Service, Order No. 7518, Reg. Doc. No. 60 (Del. PSC 2009); In re Investigation into the Adoption of Proposed Rules and Regulations to Accomplish Integrated Resource Planning for the Provision of Standard Offer Service, Order No. 7138, Reg. Doc. No. 60 (Del. PSC 2007).

27. *Order 6746*, *supra* note 26; The Provision of Standard Offer Supply to Retail Consumers In the Territory of Delmarva Power & Light Co., Order 7461, Doc. No. 04-391 (Del. PSC 2008); BOSTON PACIFIC CO., FINAL REPORT OF THE TECHNICAL CONSULTANT ON DELMARVA'S 2008-2009 REQUEST FOR PROPOSALS FOR FULL REQUIREMENTS WHOLESALE ELECTRIC POWER SUPPLY TO DELAWARE'S STANDARD OFFER SERVICE CUSTOMERS (Del. PUC 2009).

power to be developed in 2009-10. In statements in the trade press, Delmarva has noted that purchased off-shore wind is two to three times more costly per kwh than on-shore wind. A recent workgroup supporting the Governor's Energy Advisory Council has recommended that a state-wide energy efficiency and conservation program be developed employing smart grid technology, that up to 2000 MW of off-shore wind be developed by 2019, and that consideration be given to developing additional natural gas fired generation in Southern Delaware. [28] Delmarva is implementing a DEL PSC approved smart meter field test to permit designing a state-wide program next year, and will file a rate case to implement rate decoupling in 2009.[29]

B. District of Columbia

Rate caps also expired in DC in 2006 resulting in a substantial price increase. In response, the DC PSC instituted a proceeding to examine and improve the multi-phase bidding process through which electric supply is purchased for retail sale in the wholesale market.[30] On March 31, 2009, Potomac Electric Power company (PEPCO) gave notice that it would build two 230 kv underground transmission lines to alleviate service reliability problems in its service territory. PEPCO has also implemented with DCPSC approval (i.e. July 2008) an advanced metering and innovative pricing pilot including the free installation of smart meters and thermostats and covering 2000 randomly selected customers for a two year period. The objective is to provide customers with real time service cost information and means to react by reducing usage.[31] Finally, PEPCO filed an application in May 2009 for a $51.7 million increase in distribution service revenues to become effective early in 2010, and has continued competitive wholesale procurement of power supply for SOS service, the most recent of which produced only a 2.7% annual average price increase.[32]

C. Maryland

Price caps expired in Maryland in 2006 during a high price period resulting from the aftermath of Hurricane activity and thus resulting in forty to seventy percent price increases for service from Maryland's four largest electric utilities.

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28. *See, e.g.* Review and Approval of the Request for Proposals for the Construction of New Generation Resources, Order No. 7440, Doc. No. 06-241 (Del. PSC 2008); *Delmarva Power's Smart Meter Field Test Gets Under Way in Delaware*, RESOURCE WEEK, Apr. 12, 2009, at 191; *Delmarva Gets OK to Buy Wind*, ENERGY RESOURCE, Oct. 8, 2008, at 1; *Advisers Urge Delaware Governor to Back Utility Decoupling*, ELECTRIC POWER DAILY, Jan. 9, 2009, at 1.

29. Revenue Decoupling Mechanisms, Reg. Doc. 59, Doc. 07-28, Order 7420 (Del. PSC 2008).

30. Development and Designation of Standard Offer Service, Order 13741 (D.C. PSC 2005); Standard Offer Service, Order 14621 (D.C. PSC 2007).

31. Potomac Electric Power Co. (PEPCO), Formal Notice of Plans to Construct Two 230 kV Underground Transmission Circuits (March 31, 2009); Press Release, PEPCO, Residential Pilot to Test "Smart Metering" for D.C. Electric Customers (July 15, 2008), *available at* http://www.pepco.com/welcome/news/archives/2008/article.aspx?cid=1000.

32. D.C. PSC, Fact Sheet: D.C. Commission Opens Formal Case on PEPCO's Request to Increase District Serv. Rates (2009), http://www.dcpsc.org/pdf_files/hottopics/Pepcp_Request_to_Increase_Distribution_Service_Rates.pdf (last visited Oct. 12, 2009); Press Release, D.C. PSC, New PEPCO Increases Lower Than In Previous Year (May 21, 2009), *available at* http://www.dcpsc.org/pdf_files/hottopics/PressRelease_New_Pepco_Increases.pdf.

The Maryland Legislature adopted further transition procedures (i.e. a phase-in of the proposed cost increases), which legislation also imposed new regulatory approval requirements upon mergers or sales of Maryland utility assets. That legislation also provided certain rebates of previously collected charges to ratepayers, relieved ratepayers from the obligation to provide decommissioning funds for the Calvert Cliffs nuclear plant and restricts BG&E's next future rate increase to no greater than five percent and not to take effect before October 2009.[33] Additional legislation (S.B. 400) was enacted directing the MD PSC to examine longer term solutions to perceived problems in the competitive retail electric market and adopting a state-wide DSM and conservation program.[34] That legislation requires that programs be implemented to achieve per capita energy use reductions of ten percent and a fifteen percent reduction in peak demand as compared to 2007 levels by the end of 2015. In a series of Orders issued in September 2008,[35] the Maryland Public Service Commission (MD PSC) largely approved utility filed demand response programs with modifications designed to enhance their cost-effectiveness and availability to all customers. In a subsequent Order, noting that PJM projected a shortage of capacity as early as 2011 absent timely completion of major transmission lines from the west, the MD PSC directed that the State's utilities procure 400 MW of additional demand response to close that gap as to Maryland.[36] Although not part of the statutory program, the MD PSC has before it proposals from each of Maryland's major utilities to implement smart grid pilot projects (including advanced metering) that, if successful, will permit expansion of future demand response programs. Maryland has also adopted a Renewable Energy Performance Standard and is actively seeking more stable pricing from such supply sources.[37]

In response to S.B. 400, the MD PSC has commissioned a number of studies of options to alter retail market structures to obtain more stable and lower cost electric service, including mandatory long-term supply contracting and re-regulation.[38] In its Final Report on these topics, however, the Commission

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33. Pub. Serv. Comm'n- Nuclear Decommissioning, Electric Industry Restructuring, and Acquisition and Financing Approvals, 2008 Md. Laws ch. 133; Pub. Serv. Comm'n-Electric Industry Restructuring, 2006 Md. Laws ch 5.

34. EmPOWER Maryland Energy Efficiency Act of 2008, 2008 Md. Laws ch. 13; *amending* § 7-211 of the Public Utilities Company Article, 2007 Md. Laws ch. 549.

35. Baltimore Gas & Electric Co.'s Energy Efficiency, Conservation and Demand Response Program, Order 82384, No. 9154 (MD PSC 2008); PEPCO's Energy Efficiency, Conservation and Demand Response Program, Order 82385, No. 9155 (MD PSC 2008); Potomac Edison Co.'s Energy Efficiency, Conservation and Demand Responsibility Program, Order 82383, No. 9153 (MD PSC 2008).

36. New Generation to Alleviate Potential Short-Term Reliability Problems, Order 82511, Case 9149 (MD PSC 2009).

37. MD. ANN. CODE, PUB. UTIL. COS. § 7-703 (West 2009); Tim Tiernan, *PEPCO Signs Contracts for Advanced Meters*, ELECTRIC UTILITY WEEK, Mar. 30, 2009, at 4; *Alleghany Power's Maryland Efficiency Plan Includes Decoupling Mechanisms, Smart Grid*, ELECTRIC UTILITY WEEK, Sept. 8, 2008, at 6; *BG&E Lays Out Dynamic Pricing Options in Pilot Program to Gauge Customer Reactions*, ELECTRIC UTILITY WEEK, Apr. 7, 2008, at 35.

38. MD PSC, INTERIM REPORT OF THE PUBLIC SERVICE COMMISSION OF MARYLAND TO THE MARYLAND GENERAL ASSEMBLY PART I (Dec. 3, 2007); KAYE SHOLER, L.L.P., ET AL., STATE ANALYSIS AND SURVEY ON RESTRUCTURING AND REGULATION (Nov. 30, 2007); KAYE SHOLER, L.L.P., ET AL., ANALYSIS OF OPTIONS FOR MARYLAND'S ENERGY FUTURE (Nov. 30, 2007).

concluded that it cannot recommend that the legislature seek to return the existing generation fleet to full cost-of-service regulation, noting that the transaction cost and practical difficulties of this approach render it undesirable. Rather the Report recommends "incremental, forward looking re-regulation" where cost beneficial and appropriate. This will include both consideration of mandating long-term supply contracting and self-build of new generation.[39] Despite support from powerful political forces, re-regulation legislation failed to pass the Legislature in 2008 and to date in 2009 and the MD PSC has not acted upon its Reports' recommendations other than to encourage renewable energy sources and conservation development. Electric supply to provide default service continues to be obtained from a managed supply portfolio through a MD PSC administered bid auction process.[40]

Finally, in Fall 2008 during the credit crisis, Constellation Energy, parent to BG&E, experienced a severe liquidity crisis when collateral requirements relative to its energy trading operations were greatly increased, causing it to look for a merger partner or to consider a bankruptcy filing. Initially, an agreement was reached with Mid-American Energy Holdings who proposed to provide a $1 billion immediate capital infusion to be credited toward a $4.7 billion acquisition of Constellation. However, the French national electric service provider, EDF, a shareholder and joint venture partner with Constellation in certain new nuclear generation development projects, in December, proposed a $4.5 billion acquisition of approximately fifty percent of Constellation's nuclear operations and with a similar immediate $1 billion capital infusion. Constellation's Board determined this to be an offer of greater value to shareholders, and it has been accepted in preference to that of Mid-American. In June 2009, the MD PSC rejected arguments of Constellation/EDF that the acquisition did not require its approval as it found that EDF would, as the result of the transaction, "acquire directly or indirectly, the power to exercise . . . substantial influence over the policies and actions" of BG&E. The transaction has already received approval from FERC and the NYPSC, but approval remains pending in Maryland.[41] The MD PSC has before it certificate applications to permit expansion of the Calvert Cliffs Nuclear Station to add a 1,640 MW third unit, to approve a new 500 kv line to run from Virginia to New Jersey and to approve a 640 MW natural gas fired generating plant to be constructed by a non-utility power supplier.[42] Also, the MD PSC has several distribution service provider rate cases before it, and has expressed concern (i.e. opening an investigation) as to limited wholesale

39. MD PSC, Final Report Under S.B. 400: Options for Re-regulation & New Generation (2008).

40. *See, e.g.* Investigation of Investor Owned Electric Companies' Standard Offer Service for Residential and Small Commercial Customers, Order No. 82105, No. 9117 (MD PSC 2008); In re Investigation Into Default Service For Type II Standard Offer Service Customers, Order No. 82621, No. 9056 & 9064 (MD PSC 2009). Multiple auctions were required to obtain full required supplies as a number of bids were rejected as non-conforming or due to high prices. *See* In re Competitive Selection of Electricity Supplier/Standard Offer or Default Service For Investor-Owned Utility Small Commercial Customers & Residential Customer, Order 82279 & 82316 (MD PSC 2008).

41. Current and Future Financial Condition of Baltimore Gas & Electric Co., Order 82719, No. 9173 (MD PSC 2009).

42. *See, e.g.* Staff Report, *CPV, Md. County to Develop 640 MW Plant*, ELECTRIC POWER DAILY, Dec. 12, 2008, at 8; Mary Powers, *Regulators Back Expansion of Calvert Cliffs But Environmentalists Ask for Preconditions*, ELECTRIC UTILITY WEEK, Dec. 1, 2008, at p. 28.

supplier participation in the State's managed supply portfolio acquisition auction.[43]

D. New Jersey

On October 22, 2008, New Jersey released the final report under the Energy Master Plan (EMP) that Governor Corzine proposed in October 2006 to create a long-term "energy vision" to meet the state's energy needs through 2020.[44] The EMP laid out a series of action steps and strategies to achieve the following five goals:

(1) maximize New Jersey's energy conservation and energy efficiency to achieve reductions in energy consumption of at least twenty percent by 2020;

(2) reduce peak demand for electricity by 5,700 MW by 2020;

(3) meet 22.5% of New Jersey's electricity needs from renewable sources;

(4) develop new low carbon emitting, efficient power plants to help close the gap between the supply and demand of electricity; and

(5) invest in innovative clean-energy technologies and businesses to stimulate that industry's growth in New Jersey.

The EMP requires all utilities to submit a master plan for their respective territories that addresses the goals and action items raised in the EMP through 2020. On January 28, 2009, the New Jersey Board of Public Utilities (NJBPU or Board) issued an order requiring all utilities to file their respective master plans by December 31, 2009.[45] Utilities will have periodic reporting obligations and will ultimately make energy efficiency program filings that are intended to meet the goals stated in the EMP. Legislative action based upon EMP recommendations likely will be required.

In February 2009, the Board approved the results of an auction held to secure Basic Generation Service (BGS).[46] The BGS Auctions secure the supplies necessary to serve the electricity requirements of New Jersey's four electric distribution companies: Atlantic City Electric, Jersey Central Power & Light, Public Service Electric & Gas (PSE&G) and Rockland Electric. The approval covers the results of two descending clock auctions – one for fixed price service used primarily by residential as well as small and medium sized commercial customers, and the other for hourly priced service used by large commercial and industrial customers. The fixed price service is determined on a three year rolling average of the most recent fixed price auction results. The

43. *See, e.g.*, Mary Powers & Tom Tiernan, *Maryland to Probe Low Number of Bidders in State's Wholesale Auction for Power*, ELECTRIC UTILITY WEEK, May 4, 2009 at 27; Competitive Selection of Electricity Supplier/Standard Offer of Default Service, Order 82409, No. 9064 (MD PSC 2009); In re Delmarva Power & Light Co., Order 82676, No. 9192 (MD PSC 2009); Columbia Gas of Maryland Inc., Order 82261, No. 9159 (MD PSC 2009).

44. N.J. Energy Master Plan (2008), http://www.state.nj.us./emp./docs/pdf/081022_emp.pdf (last visited Oct. 10, 2009).

45. Development of Individual Utility Territory Energy Master Plans, Doc. EO08121065 (NJ BPU 2009).

46. Basic Generation Service for the Period Beginning June 1, 2009 – Auction Results, Doc. ER08050310 (NJ BPU 2009).

prices for energy secured in the hourly price auction last only one year, The 2009 fixed price auction produced prices that are six to ten percent lower than 2008, but under the terms of the program, overall prices will fall somewhere between no change and an increase of 0.6%, effective June 1, 2009. Prices for the hourly priced auction averaged a ninety-one percent increase from 2008, from $107.63 per MW-Day to $205.20 per MW-Day. As a result, large commercial and industrial customers are expected to see an increase of approximately seven percent in their overall energy bills.

In October 2008, the Board voted to award a $4 million grant to Garden State Offshore Energy to develop a 345.6 MW offshore wind farm 16 miles southeast of Atlantic City. There are currently no offshore wind farms off the east coast of the United States. Also, in April 2008, the Board approved a solar pilot program proposed by PSE&G to provide upfront capital to install 30 MW of solar capacity. PSE&G will offer $100 million in loans to help finance the installation of solar systems on homes, businesses and municipal buildings throughout its electric service area. PSE&G customers will repay the loans over ten to fifteen years by providing Solar Renewable Energy Credits to PSE&G.[47]

E. New York

In February 2009, the New York Public Service Commission (Commission) issued an order that initiated a proceeding to examine potential initiatives to promote demand response in the parts of the state where peak load reduction would provide the greatest benefits. The proceeding will focus initially on demand response efforts in the New York Independent System Operator (NYISO) Zone J, served by Consolidated Edison Company (Con Ed), where demand response is expected to be the most cost-effective.[48] In April 2008, the Commission issued a policy statement on the recovery and allocation of costs for backstop projects, which facilitate development of new resources by ensuring construction of electric infrastructure or, alternatively, that sufficient energy demand reductions occur if the market is not able to address the energy needs and related public policy goals of New York. Backstop project costs would be submitted by the utility to the Commission for recovery authorization.[49] The Commission adopted the principle that reasonably-incurred costs for generation and demand-based projects that it authorizes will be recoverable. In February 2009, the Commission issued another policy statement, addressing project approval for backstop projects. The adopted process calls upon Commission staff to continue regular monitoring of the NYISO "Comprehensive Reliability Planning Process." If Staff determines that the need for a backstop solution is reasonably likely, Staff would begin a more formal review. The Commission

47. Press Release, N.J. BPU Approves Grant of $4 Million for Offshore Wind Project Proposal (Oct. 3, 2008); In re Petition of PSE&G for Approval of a Solar Energy Program, Doc. EO07040278 (NJ BPU 2008).

48. PSC Acts to Reduce NYC Elec. Demand, Doc. 09029/08-E-1463 & 08-E-0176 (NY PSC 2009); Demand Response Initiatives, No. 09-E-0115 (NY PSC 2009). In June and August 2008, the NY PSC had established an Energy Efficiency Portfolio Standard and issued a Policy Statement respecting the appropriateness of Distributor financial incentives to further development of those programs. In re Energy Efficiency Portfolio Standard, No. 07-M-0548 (NY PSC 2008).

49. Proceeding to Establish a Long-Range Electric Resource Plan and Infrastructure Planning Procedure, No. 07-E-1507 (NY PSC 2009); Policy Statement on Backstop Project Cost Recovery & Allocation, No. 07-E-0157 (NY PSC 2008).

would make the ultimate determination regarding the selection of the appropriate regulated solution to the reliability need.

In March 2008, the Commission authorized Con Ed to recover only $425 million of a requested $1.2 billion revenue requirement increase. That amount could be reduced by an additional $152 million if Con Ed fails to meet certain customer service and system reliability performance targets. In April 2009, in response to a second rate case, the Commission authorized Con Ed to collect an additional proposed $721 million. In July 2008, the Commission authorized Orange and Rockland, a Con Ed affiliate, to increase rates by nearly $15.6 million in each of the three rate years ending June 30, 2009, 2010, and 2011. The Commission, however, dismissed rate filings by Energy East affiliates, New York State Electric & Gas and Rochester Gas and Electric.[50] Under the conditions of their recent acquisition by Iberdrola, the utilities are prohibited from filing for rate relief unless they can demonstrate that their ability to provide safe and reliable service would be jeopardized. The Commission concluded that was not the case.[51]

The Commission also issued several Orders addressing electric and natural gas retail market design issues. In March 2008, it approved with modifications tariff amendments to implement and clarify its previous Order adopting a capacity release requirement applicable to local distribution companies for natural gas interstate pipeline capacity.[52] In October 2008, the Commission issued a further Order in its examination of electric retail market access programs, and particularly directing the continuation of Distributor customer education programs respecting market operations and access.[53] The New York Regional Interconnect, a proposed 200 mile 400 kv direct current transmission line to traverse New York State, sought an Article VII Certificate to authorize construction, but withdrew its proposal during evidentiary hearings in the face of extensive public opposition. Also, the Commission has held a Technical Conference and initiated consideration of a Smart Grid Initiative.[54] Finally, in September 2008, the Commission approved the acquisition of Energy East by

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50. Consolidated Edison Co., No. 08-E-0539 & 08-M-0618 (NY PSC 2009); Consolidated Edison Co., 264 P.U.R.4th 34 (NY PSC 2008); Orange & Rockland Util. Inc., No. 07-E-0949 (NY PSC 2008). On February 12, 2009, the NY PSC initiated a Prudence Proceeding to examine the prudence of the Company's payments to contractors for electric, gas, and steam capital projects and certain operation and maintenance activities. Certain Refunds Possible If Certain Expenditures Deemed Imprudent, No. 09062/09-M-0114 (NY PSC 2009). Also, in September 2008, the NY PSC reviewed Consolidated Edison's performance under its Electric Service Reliability Performance Mechanism, determining that the Company had failed to meet two performance requirements and thus must credit $9 million in penalties to the benefit of ratepayers. Consolidated Edison Co., No. 04-E-0572 (NY PSC 2008).

51. New York State Electric & Gas Corp. and Rochester Gas & Electric Corp., Nos. 09-E-0082 - 0085 (NY PSC 2009).

52. Issues Associated with the Future of the Natural Gas Industry and the Role of Local Distribution Companies – Capacity Planning and Reliability, No. 07-G-0299 (NY PSC 2008).

53. Policies and Practices Intended to Foster the Development of Competitive Retail Energy Markets, No. 07-M-0458 (NY PSC 2008). The NY PSC also adopted a 15% Installed Reserve Margin for use in market operations during the 2008 Capability Year. Installed Reserve Margin for the New York Control Area, No. 07-E-0088 & 05-E-1180 (NY PSC 2008).

54. *See, e.g.* NY PSC, New York Interconnect, http://www.dps.state.ny.us/NYRI.htm (last visited Oct. 10, 2009); NY PSC, Smart Grid Initiative, http://www.dps.state.ny.us/09-E-0310.html (last visited Oct. 10, 2009).

the Spanish Company, Iberdrola, though after imposing numerous conditions.[55] Principal conditions included establishing performance targets related to operational safety, service reliability and consumer protection with financial penalties should they not be met; a requirement for $200 million in new wind investments over the next two years or alternative economic development projects and to maintain a specified level of investment in Energy East; divestiture of all fossil generation plants and sharing ninety percent of proceeds above book value with ratepayers, continued use of US generally accepted accounting standards and other protective measures related to financial matters; and to allocate to ratepayers at least $275 million of synergy and efficiency savings to be derived from the acquisition.

F. Pennsylvania

On December 31, 2009, the price caps adopted as transition to competitive electricity markets expire for one of Pennsylvania's seven major electric utilities and on December 31, 2010 they expire for four additional major companies. The Pennsylvania Consumer Advocate[56] has estimated that, immediately following expiration, price increases of between twenty and sixty percent could be experienced by affected end-users. A major focus of Pennsylvania's Governor, General Assembly and the Public Utility Commission (PA PUC) during this Reporting Period has been development of programs to mitigate this possible effect, to enhance the likelihood of stability in future competitive market based prices in Pennsylvania and to offer programs to end-users that will reduce the cost of their service to the maximum extent reasonable. The principal vehicle for this effort has been legislation proposed in the General Assembly, a part of which was adopted on October 15, 2008 as Act 2008-129.[57] Act 129 mandates the development of a state-wide Energy Efficiency and Conservation Program, the provision of default service pursuant to a PA PUC approved "competitive procurement plan" employing one or more statutorily defined approaches and with a "prudent mix" of spot market purchases, short-term contracts and long-term contracts (i.e. four to twenty years and not to exceed twenty-five percent of supply unless approved by the Commission) and the adoption of smart meter technology and time of use rates. The PA PUC has conducted a series of collaborative proceedings involving the public and interested stakeholders to implement the Act, and has issued a series of Orders.[58] The latter have

55. Joint Petition of Iberdrola S.A., Energy East Corp., *et al*., Abbreviated Order Authorizing Acquisition Subject to Conditions, No. 07-M-0906 (NY PSC 2008); Joint Petition of Iberdrola S.A., Energy East corp., Case 07-M-0906 (NYPSC 2009).

56. Testimony of Sonny Popowsky, Consumer Advocate, Regarding Electricity Rate Mitigation, H.B. 20 before the PA House Consumer Affairs Committee (Mar. 26, 2009), *available at* http://www.oca.state.pa.us/Testimony/2009/House%20Consumer%20Affairs%20Test.%20--%20HB%2020%20--%20March%2026,%202009%20_00110156.pdf.

57. H.B. 2200, 192 Gen. Assem., Reg. Sess. (Pa. 2008) [hereinafter, *Act 129*].

58. *See, e.g.*, Energy Efficiency and Conservation Program, Docket No. M-2008-2069887 (PA PUC 2009) [hereinafter, *Implementation Order*]; Implementation of Act 129 of 2008, Phase 2 – Registry of Conservation Service Providers, Docket No. M-2008-2074154 (PA PUC 2009) [hereinafter, *PA PUC Feb. 2, 2009*]; Energy Efficiency and Conservation Program, Docket No. M-2008-2069887 (PA PUC 2009) [hereinafter, *PA PUC May 28, 2009*]; Implementation of the Alternative Energy Portfolio Standards Act of 2004: Standards for the Participation of Demand Side Management Resources – Technical Reference Manual

established implementation procedures, defined program evaluation standards (i.e. separately for conservation programs and smart meter implementation programs), qualifications required of Conservation Service Providers and other matters. Energy Efficiency and Conservation Programs are to be filed July 1 and to be approved by the Commission by year-end. Smart Metering implementation programs are to be filed August 14 and a timeline for Commission review and approval by mid-Spring 2010 and implementation in 2011 has been established.[59]

Additional actions taken to mitigate possible price increases include proposed legislation to phase-in such increases over a three year period (i.e., presently pending before the General Assembly), utility efforts to acquire a managed portfolio of supply contracts which minimize prices by acquiring only modest portions of supply in any one auction (and employ up to six auctions) to begin service with the expiration of price caps, establishment of pre-payment programs to permit customers to begin paying today toward the increased costs expected once the caps expire and enhanced default service provider regulations. Managed portfolios include a mixture of planned spot market purchases and bilateral short-term contracts (typically one to three year terms) entered into over a several year period such that not more than ten to fifteen percent of required electric supply is purchased at a single time.[60] Pennsylvania has also adopted a Renewable Portfolio Standard which utilities are implementing in their Commission reviewed procurement plans, has expanded net-metering programs and payment options and the PA PUC has held three en banc hearings to examine and obtain stakeholder input as to the operation and status of regional wholesale electric markets.[61]

On November 13, 2008, the PA PUC issued its Order resolving the Application of Trans-Alleghany Interstate Line Company (TrAILCO – a subsidiary of Alleghany Electric System), to construct the Pennsylvania portion

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Update, Docket No. M-00051865 (May 28, 2009); Implementation of Act 129 of 2008 – Total Resource Cost (TRC) Test, Docket No. M-2009-2108601 (PA PUC 2009) [hereinafter, *PA PUC Jun. 18, 2009*].

59. Regulated electric service providers must develop and obtain PA PUC approval of programs to achieve a 1% reduction in their June 2009 to May 2010 load by May 31, 2011, and of 3% by May 31, 2013. In addition, peak demand is to be reduced by 4.5% also by May 31, 2013. Failure to achieve these objectives can result in a fine of up to $20 million and direct PA PUC development and implementation of a replacement program. Total cost of the program adopted may not exceed 2% of utility revenues, and recovery of program costs is provided for either in base rates or by a separate rate adjustment clause. If successful, the PA PUC may adopt more aggressive reduction objectives and extend the program for future five year periods. *Act 129*, *supra* note 57, at § 2.

60. Press Release, PA PUC, PUC Finalizes Directives to Remove Barriers to a Competitive Retail Electric Market in the PPL Service Territory, PA PUC (Aug. 6, 2009); Press Release, PA PUC, PUC Approves PPL's Plan to Mitigate Projected Rate Increases, PA PUC (July 23, 2009); West Penn Power Co. for Approval of its Retail Default Service Program and Competitive Procurement Plan for Service at the Conclusion of the Restructuring Period, Docket P-00072342 (PA PUC 2008); Petition of PPL Electric Utility Corp. for Approval Of a Comprehensive Bridge Plan, Docket No. P-0006227 (PA PUC 2007); Electric Distribution Companies Obligations to Serve Residential Customers at the Conclusion of the Transmission Period, Docket No. L-00040169 (PA PUC 2007); Policies to Mitigate Potential Electricity Price Increases, Docket No. M-000611957 (PA PUC 2007); Default Service and Residential Electricity Markets, 256 P.U.R.4th 341 (PA PUC 2007).

61. PA PUC, *Wholesale Energy Markets En Banc Hearings* (Dec. 18, 2008), *available at* http://www.puc.state.pa.us/electric/electric_issues_wholesale_markets_enbanc_hearings.aspx; PA PUC, Alternative Energy Portfolio Standards (AEPS) Program Website, http://www.puc.state.pa.us/electric/electric_alt_energy.aspx (last visited Oct. 10, 2009).

of a 240 mile 500 kv transmission line from just within the Pennsylvania border through West Virginia and into Northern Virginia, where the line will interconnect with additional lines extending to New Jersey and Eastern Pennsylvania, and certain local Pennsylvania transmission facilities (i.e. fifty-one miles of 138 kv lines needed to serve load in southwestern Pennsylvania).[62] The much more substantial segments of the interstate line in Virginia and West Virginia have already been certificated by Commissions in those states (as described below), but those approvals were conditioned on favorable action by Pennsylvania. TrAILCO'S Pennsylvania Application was complicated by its combination with the local transmission lines, which were heavily opposed by local landowners. The PA PUC, by a four to one vote, approved and certificated the 1.2 mile segment of the interstate line and associated substation, finding that its reliability and economic need had been demonstrated, that its siting was proper as dictated by the need to connect at an existing West Virginia substation and that minimization of its environmental effect and possible safety effects had been shown. As respects the local transmission lines (i.e. the Prexy Facilities), the PAPUC (by a three to two vote) granted a request from TrAILCO that a stay be granted upon its Application for certification of these facilities and that the Commission encourage the formation of a collaborative discussion among interested litigants to determine if alternative, less environmentally intrusive solutions to the reliability needs could be identified.[63] On July 23, 2009, a Joint Petition for Settlement resulting from this collaborative effort was filed with the PAPUC, providing for a more limited transmission solution of the demonstrated near-term reliability needs (i.e. one new tower and certain line reconductoring and substation expansion), but a solution which fails to address longer term growth needs addressed by the Prexy proposal.[64] The matter remains pending before the PA PUC, and its November 2008 Order has been appealed.

In October 2005, the PA PUC, in a Report to the General Assembly on Pennsylvania's Natural Gas Supply Market, concluded that effective competition in Pennsylvania's retail natural gas market did not exist. As a result, it was required to convene a Natural Gas Stakeholders Group to explore means of correcting this result. On September 11, 2008, the PA PUC issued its Order defining an action plan for this purpose. Proposed actions include establishing an Office of Competitive Market Oversight within the PUC, expansion of the purchase of receivables to encourage market participation of alternative suppliers and the conduct of a number of further rulemakings with the objective of expanding alternative supplier participation in the market.[65] Traditional rate cases adjudicated and supply cost reductions, a proposed revision to Guidelines for Maintaining Customer Services related to utility purchase of receivables from competitive natural gas suppliers, a statewide investigation of electric distribution company service outage response and restoration practices, a natural

62. Application of Trans-Allegheny Interstate Line Co., Docket Nos. A-110172 & G-00071229 (PA PUC 2008).

63. *Id.* at 7-12.

64. *See, e.g.* Application of Trans-Alleghany Interstate Line Co., Statement of the Office Of Conservation Advancement in Support of Settlement & Trans-Allegheny Interstate Line Co. Statement in Support of Settlement, PA PUC Docket Nos. A-110172 & G-00071229 (2009).

65. Investigation into the Natural Gas Supply Market, Docket I-00040103F0002 (PA PUC 2008).

gas company corporate reorganization and a transfer between Pennsylvania utilities of a natural gas service territory (76,191 customers) are cited in the note below.[66]

III. SOUTHERN REGION

None of the ten states examined in the Southern Region, except Virginia, restructured their electric industry and pursued competitive retail electric markets. Competitive wholesale markets, established under FERC jurisdiction, do operate throughout the region and are employed both by Regulators and Utilities to obtain electric supply. State Regulators have adopted procurement regulations providing for the evaluation of both short and long-term supplies available in such markets on a non-discriminatory basis in comparison to regulated supply, and utilities sell generation in excess of their regulated or contracted wholesale service obligations into that wholesale market. Several states, have established retail competitive natural gas markets. For this reason, the focus and objectives of State regulatory proceedings in the Southern region are somewhat different from that of the mid-Atlantic or New England regions where support of retail market activities is a major focus. Most Southern states have active generation certification proceedings in process or recently completed (i.e. often nuclear and coal-fired plants) and traditional base rate proceedings which are, in part, directed at recovering the early costs of this plant development. However, concerns with transmission and renewable energy development, and with expanding conservation, DSM and energy efficiency programs, are common activities.

A. Alabama

The Alabama Public Service Commission (AL PSC) regulates a single electric company (Alabama Public Service Company) and two natural gas companies (Alabama Gas Corp. & Mobile Gas Service Corp.). The AL PSC, as it has since 1983, employs in rate regulation of these three companies a Rate Stabilization and Equalization Factor (the RSE).[67] The RSE is reviewed and its components established during periodic rate cases, and then it permits annual rate adjustments for increased costs or investment to maintain the allowed equity return within a range in intervening years. The purpose of the RSE has been explained by the AL PSC as follows:

It is the purpose of Rate RSE to lessen the impact, frequency and size of retail rate increase requests by permitting the Company, through the operation of

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66. *See, e.g.* PA PUC Secretarial Letter, Revision of Guidelines for Maintaining Customer Services – Establishment of Interim Standards for Purchase of Receivables (POR) Programs, Docket No. M-2008-2068982 (October 16, 2008); PA PUC STAFF REPORT, ELECTRIC DISTRIBUTION CO. SERVICE OUTAGE RESPONSE AND RESTORATION PRACTICES REPORT (Apr. 2009); UGI Utilities, Inc., 267 P.U.R.4th 289 (PA PUC 2008); Press Release, PA PUC, PUC OKs Lower Rate Increase Than Requested by PECO's Natural Gas Division (Oct. 23, 2008); Press Release, PA PUC, PUC Approves Lower Rate Increase than Requested by Equitable Gas Co. (Feb. 26, 2009); Press Release, PA PUC, PUC Approves Reorganization of Equitable Resources Inc. (May 22, 2008).

67. *See*, *e.g.* Alabama Public Service Commission, Energy Division Website, http://www.psc.state.al.us/Energy/EnergyMain.htm; In re Alabama Gas Corp., 262 P.U.R.4th 556 (AL PSC 2007); ALABAMA POWER CO., RATE RSE RATE STABILIZATION AND EQUALIZATION FACTOR, Docket.Nos. 18117 & 18416 (Al. PSC 2005).

a filed and approved rate, to adjust its charges more readily to achieve the rate of return allowed it in the rate order of the Commission. By provisions in the rate, the charges are increased if projections for the upcoming year show that the designated rate of return range will not be met and are decreased if such projections show that the designated return range will be exceeded. Other provisions limit the impact of any one adjustment (as well as the impact of any consecutive increases), and also test whether actual results exceeded the equity return range.[68]

In addition to the RSE, the PSC adjudicates annual Energy Cost Rate filings to recover variable electric generation fuel and natural gas costs.[69]

In 2007-2009, the Commission also adjudicated a number of Alabama Power requested expansions to its Renewable Energy and Conservation Programs. These include an expansion in its Rate Rider RE (under which customers may purchase renewable energy in blocks for an incremental payment over typical rates) to permit commercial and industrial customer participation, and extension of Rate Rider CPP (i.e. critical peak pricing) beyond its original expiration date employed in a smart metering pilot project for customers who elect to be served on Rate FDT (Family Dwelling Time-of-use). This rate provides price signals based upon which a residential energy management system automatically adjusts residential heating and cooling to minimize system peak and customer costs. The AL PSC also approved Rate Rider DLC (Direct Load Control) which establishes an optional program under which residential customers agree to restrict usage of their air conditioner or heat pump during defined peak periods in return for a twenty dollar annual credit for participation in the program.[70] The PSC further evaluated Federal Standards adopted in §§ 1251-1254 of the Energy Policy Act of 2005,[71] (i.e. development of a ten year plan for fuel optimization and diversification of generation fuel source), and determined not to adopt these standards as Alabama's statute mandated Integrated Resource Planning program, including its active DSM and Energy Efficiency program components, already fully accomplished the purposes of these standards.[72]

B. Arkansas

In 2007-09, the Arkansas Public Service Commission (APSC) authorized Southwest Electric Power Co. (SWEPCO) to construct a new 600 MW coal-fired generating plant (known as the Turk Plant) in Hempstead Co., Arkansas—only to see the state Court of Appeals, in a June 24, 2009 ruling, reverse that

68. *See, e.g.* AL PSC, Energy Division, Electricity Section, (last http://www.psc.state.al.us/Energy/electricity2.htm (last visited Oct. 10, 2009).

69. Modified Rate ECR Factor, Docket No. 18148, 2007 WL 1975064 (AL PSC 2007).

70. Revisions to Rider RE, Informal Docket No. U-4485 (AL PSC 2007); Rate Rider CPP, Informal Docket No. U-4732 (AL PSC 2008); Rate Rider DLC, Informal Docket No. U-4917 (AL PSC 2008). With the exception of Rate Rider DLC, these programs had been initiated at Company request in 2003 to 2005.

71. Energy Policy Act of 2005, §§ 1251 to 1254, 119 Stat. 963-970 (2005).

72. Consideration of §§ 1251 & 1254 of the Energy Policy Act of 2005, Docket No. 30066 (AL PSC 2008).

determination.[73] The Court found that the APSC, by segmenting its review of SWEPCO's capacity expansion plan into separate proceedings examining the overall system resource need, the generation plant impact, and the transmission facilities impact, had failed to correctly apply the certification statute,[74] which contemplates the APSC's review of all these aspects in a single proceeding. In any further proceedings before the APSC to justify the Turk Plant, the Court held, SWEPCO must show "need" directly in the context of this proposed facility (as opposed to a generic system need for baseload generation), and must also compare the Hempstead Co. site to alternative locations.[75] SWEPCO has petitioned the Arkansas Supreme Court to review the Court of Appeals decision.

Yet another significant regulatory initiative was the APSC's exploration of the "expanded development of Sustainable Energy Resources (SER)."[76] The initial Order (October 2008) identified four major categories of SER: Energy Efficiency, Demand Response, Automatic Metering Infrastructure (including "Smart Grid" technology), and Renewable Resources. While it had implemented an energy efficiency program three years earlier, the APSC saw the need to build substantially on that foundation against a backdrop of rising end-use demand, the necessary retirement of aging and inefficient generators, sharply increasing fuel and construction costs,[77] national policies leading away from heavy reliance on carbon-emitting generation technologies, and national security concerns over dependency on imported fuel inputs. By convening a series of public forums and accepting written comments, the APSC intends to survey what is being done currently, in the state and elsewhere, to encourage the deployment of SER; the technical potential to expand SER (given various economic assumptions); what new Federal and state laws and policies are on the horizon or may be advisable; what regulatory barriers should be lowered to encourage utilities to include SER in their resource plans, and what incentives might optimize SER development. On other fronts, the APSC (1) declined, in a May 29, 2008 order, to adopt a Federal standard under PURPA[78] that would require utilities to frame ten year plans for improving their fossil fuel generation efficiency (concluding that existing state laws and APSC programs effectively accomplished this goal);[79] and (2) approved an approximately $13.5 million base rate increase for Oklahoma Gas & Electric that resulted from a settlement agreement and should

73. Hempstead Co. Hunting Club, *et al.* v. Arkansas Pub. Serv. Comm'n, 2009 Ark. App. Lexis 555 (Ark. Ct. App. June 24, 2009).

74. The Utility Facility Environmental and Economic Protection Act, ARK. CODE ANN., §23-18-501 (2009).

75. The court found this aspect of SWEPCO's submission and the APSC's review insufficient to meet the statutory standard. The sole support for selection of the Hempstead Co. site, it asserted, was an engineering study that, while concluding that that site would meet the requirements of the coal-fired unit, ranked it seventh on a list of ten alternatives.

76. Arkansas Public Service Commission, Docket No. 08-144-U, Order No. 1 (Oct. 7, 2008).

77. The order was issued shortly before these trends reversed themselves in the 2008 recession.

78. The requirement for state commissions to consider adopting the standard was enacted as Section 1251 of the Energy Policy Act of 2005, amending Section 111(d) of the Public Utility Regulatory Policies Act of 1978 (PURPA).

79. Arkansas Public Service Commission, Docket No. 06-028-R, Order No. 8 (May 5, 2006).

largely be offset in customers' bills by recent fuel cost declines.[80] The APSC has also initiated a docket to consider "innovative approaches" to ratemaking for electric and natural gas utilities. As examples of such approaches, the order listed annual earnings reviews, formula rates, and methods for recovering the costs of facilities acquisition or construction and extraordinary storm damages.[81] To date, numerous parties have filed comments.

C. Florida

Regulatory proceedings in Florida have focused in recent years upon planning to meet the significant growth in electricity usage being experienced in the State (i.e. 1.5 to two percent). In 2006, the Legislature enacted Florida Statute § 366.93 to encourage utility investment in base load generation. In Order No. PSC-07-0240-FOF-EI, the Florida Public Service Commission (FLA PSC) adopted rules to implement the statute.[82] Those rules provide that, once a utility has obtained a certificate of need for covered generation, it is permitted to seek recovery through rates of certain specified development costs for the plant (i.e. preconstruction and site development costs) and financing costs during construction. In 2008, both Florida Power & Light and Progress Energy Florida obtained certificates of need for construction of two unit nuclear stations with estimated costs of approximately $14 billion or more. The FLA PSC found that, given the State's policy against construction of new base load coal plants and its already heavy reliance on natural gas as a generation fuel, nuclear plant construction serves both fuel diversification needs and is cost-beneficial for ratepayers despite its apparent high capitol cost.[83] In November 2008, pursuant to Statute § 366.93, the FLA PSC approved recovery through rates beginning January 1, 2009 of over $600 million associated with development and financing costs for significant uprates at four existing nuclear plants (totaling several hundred additional MW of capacity expansion) and the four new plants certificated as described above.[84] These costs are to be recovered through a Capacity Cost Recovery Clause which will be reviewed and updated to add new qualifying costs for recovery each Fall. Certificates of need have also been granted for construction of a portion of the 8000 MW of natural gas plant capacity expected to be needed.[85]

80. Arkansas Public Service Commission, In the Matter of the Application of Oklahoma Gas & Electric Co., Docket No. 08-103-U, Order No. 6 (May 20, 2009).

81. Arkansas Public Service Commission, Docket No. 08-137-U, Order No. 1(June 25, 2008).

82. FLA. STAT. ANN. § 366.93 (2008).

83. Florida Power & Light Co., 264 P.U.R.4th 361 (FL PSC 2008); Progress Energy Florida, Inc., Docket No. 080148-EI (FL PSC 2008). In 2007, the FL PSC had rejected FP&L's request for a certificate for an 850 MW pulverized coal plant (Glades) and the Florida Department of Environment had rejected an air permit request for a similar 750 MW plant (Seminole), citing cost and environmental uncertainties related to developing GHG emission regulation. Plans to develop an IGCC plant were also abandoned by Progress Energy and it has committed to retire 866 MW of older coal plants once its new nuclear units have completed their s first operating cycle. Rejection of the Seminole air permit has been reversed, however, by an intermediate Florida Appellate Court, but the matter remains pending in the Florida court system. Absent new nuclear construction, FP&L and Progress reliance upon natural gas generation would have increased to 75 and 85% of electric supply respectively.

84. Nuclear Cost Recovery Clause, 269 P.U.R.4th 369 (FL PSC 2008).

85. Housley Carr, *Florida's Utilities, Muns., Co-ops to Add 13,500 of New Capacity Over 10 Years*, ELECTRIC UTILITY WEEK, April 13, 2009, at 16.

Florida is also pursuing both renewable energy and aggressive demand response programs. Pursuant to the terms of Florida Statute §366.92(3), the FLA PSC developed during 2008 and submitted to the Legislature on January 30, 2009 a Draft Renewable Portfolio Standard that requires investor owned utilities to employ renewable energy for twenty percent of their energy supply by 2020, and beginning with seven percent in 2013 and increasing gradually every three years.[86] Twenty-five percent of renewable energy supply is, moreover, required to be provided by wind and/or solar generation, and a utility that fails to achieve the standard can be penalized with a fifty basis point reduction in authorized return on equity. Only Florida in-state renewable generation would qualify and permitted compliance costs would be capped at two percent of gross utility revenues. The proposal must now be reviewed and enacted into law by the Legislature before it is effective. Florida's utilities have also been active in 2007-2008 in building new renewable capacity (primarily solar), and in soliciting through RFPs renewable supply projects for acquisition by contract.[87] Florida utilities have also pursued aggressive demand side management and energy efficiency programs, including demonstration projects related to new smart grid technologies such as two-way communication of pricing signals, smart meters and programmable thermostats.[88] Most of these programs date back to 2002-2003 or even earlier, and thus their development and approval are beyond the scope of this Report. However, their importance and customer benefits (i.e. estimated customer savings of more than a billion dollars over the twenty year life for each of Florida's largest two utilities) have been cited both by the Companies and the PSC as partial justification for permitting rate recovery for major base-load generation under construction.

The FLA PSC has also addressed a number of large base rate applications (i.e. the largest being that of FP&L at over $1 billion), and has issued orders permitting a substantial portion of the requested relief. In most cases, these applications reflect the first base rate application filed by the utility involved in fifteen to twenty years. Moreover, fuel clause rate reductions attributable to reductions in natural gas and coal prices generally exceed these base rate increases resulting in a net of bill reductions for customers in 2008-2009.[89] Two additional major activities have included implementation of a program to harden

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86. FLA PSC, Draft Renewable Portfolio Standard Rule (January 30, 2009) available at http://www.floridapsc.com/utilities/electricgas/RenewableEnergy/2009_FPSC_Draft_RPS_Rule.pdf#xml=http://www.psc.state.fl.us/search/pdfhi.aspx?query=Draft+Renewable+Portfolio+Standard+Rule&pr=default&prox=page&rorder=500&rprox=500&rdfreq=500&rwfreq=500&rlead=500&rdepth=0&sufs=0&order=r&mode=&opts=&cq=&id=49833a9511; Housley Carr, *Florida Bill Includes Nuclear Power in Clean Energy Requirements*, NUCLEONICS WEEK, April 9, 2009, at 5.

87. Michael Burnham, *Solar Power: Utility Breaks Ground on First Sunshine State PV Project*, E & E NEWS, Feb. 26, 2009; Housley Carr, *Progress Signs Biomass PPAs Totaling 100 MW*, ELECTRIC POWER DAILY, Aug. 14, 2008, at 7; Utility in Florida plans RFP for Renewable Energy Supplies, PLATT'S RENEWABLE ENERGY REPORT (Apr. 14, 2008), at 29.

88. Price Responsive Load Management Pilot Program of Tampa Electric Co., Docket No. 070056-EG (FL PSC 2007);. Adoption of PURPA Standard 14, Time-based Metering and Communications, Docket No. 070022-EU (FL PSC 2007).

89. Housley Carr, *Progress Seeks $99 Million Base Rate Hike*, ELECTRIC POWER DAILY, Mar. 23, 2009, at 4; Craig Cano, *FERC Moves Forward in Setting Standards for Smart Grid*, ELECTRIC POWER DAILY, Mar. 20, 2009,at 1; Florida Public Service Commission votes on Tampa Electric Base Rates and Fuel Charges that result in Lower Bills (April 26, 2009) at p. 88.

Florida's transmission and distribution systems to reduce future hurricane damage and expansion of natural gas transmission and storage in light of planned expansion of reliance on natural gas as a generation fuel.[90]

D. Georgia

Pursuant to The Natural Gas Competition and Deregulation Act adopted in 1997 and the decision of Atlanta Gas Light (AGL) to open its service territory to supply competition, ten marketers certified by the Georgia Public Service Commission (GA PSC) compete to sell natural gas supply at market prices in AGL's former service territory. Distribution rates of AGL and full service rates of Atmos Energy Corporation which did not elect to open its service territory to competition remain subject to Georgia PSC regulation.[91] 84 municipal systems also provide natural gas service on a monopoly basis but not subject to Georgia PSC regulation, and the Commission establishes under the statute a regulated default service provider selected through an RFP process. In 2007-2009, the Georgia PSC adjudicated a rate case for Atmos Energy, retained the existing default service provider for an additional two year term, revised its rules applicable to natural gas marketers to penalize actions by marketers that prevent customers from switching service between them and negotiated settlements providing for service fee credits for customers with two marketers found to have violated PSC rules by failing to advise customers of all pricing options.[92] Class action litigation remains pending against the largest natural gas marketer (i.e. Georgia Natural Gas Co., an affiliate of AGL) seeking damages for the violations.[93]

The Georgia Territorial Electric Service Act permits limited competition in electric service as large industrial or commercial customers may make a one-time choice to switch service providers or such a transfer may be made if all parties agree.[94] Electric service is provided in Georgia by a large, fully regulated investor owned company, Georgia Power, by forty-two electric cooperatives and fifty-two municipal systems, the latter two of which are largely not subject to Commission jurisdiction. On March 17, the Commission approved a Georgia Power request for certification to expand the Vogtle Nuclear Power Station to include two additional units, and further permitted the recovery of financing costs during construction of the new units (i.e. by allowing construction work in progress in rate base). In a statement, the GA PSC noted that "CWIP will save

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90. *See, e.g.* FL PSC, REPORT TO THE LEGISLATURE ON ENHANCING THE RELIABILITY OF FLORIDA'S DISTRIBUTION AND TRANSMISSION GRIDS DURING EXTREME WEATHER (July 2008), *available at* http://www.psc.state.fl.us/utilities/electricgas/eiproject.docs.AddundumSHLegislature.pdf; Jeff Barber, *Florida Power Utility Proposes New Gas Pipeline*, ENERGY TRADER, April 9, 2009, at 13; Joel Kirkland, *FERC Gives Nod to Florida Gas Storage, Cites Demand from Electric Power Sector*, INSIDE F.E.R.C., Sept. 8, 2008, at 13.

91. GA PSC website, http://www.psc.state.ga.us/gas/gas.asp (last visited Oct. 10, 2009).

92. Press Release, GA PSC, Natural Gas Marketer Accepts Settlement to Resolve Alleged Violations of PSC Rules and Georgia Laws (Mar. 6, 2008); Press Release, Georgia PSC, PSC Revises Natural Gas Rules (Feb. 5, 2008); Press Release, Georgia PSC, PSC Approves Consent Agreement to Resolve Issues with Natural Gas Marketer SCANA (Jun. 17, 2008); Press Release, Georgia PSC, Commission Retains SCANA Energy as Natural Gas Regulated Provider (Mar. 17, 2009); Atmos Energy Corp., 268 P.U.R.4th 493 (GA PSC 2008).

93. Ellison v. Southstar Energy Services, L.L.C., 679 S.E.2d 750 (Ga. App. 2009).

94. *See, e.g.*, GA PSC website, Electric, http://www.psc.state.ga.us/gas/gas.asp (last visited Oct. 10, 2009).

customers money" by reducing the burden on the Company of financing the new plant, and noted its requirement that an independent construction monitor be employed and that quarterly status reports on construction be filed with it.[95] With an effective date which followed the GA PSC decision, the Georgia General Assembly enacted the Georgia Nuclear Energy Financing Act (SB 31) to authorize recovery of the financing costs of nuclear generation facilities certificated by the Commission. The GA PSC has also approved a request from Georgia Power to convert its 155 MW Mitchell coal fired plant into a 96 MW biomass plant, employing wood waste from Georgia forestry operations. The converted plant is expected to have both lower operating costs and reduced air emissions.[96] The GA PSC also approved Georgia Power's request to expand its Green Energy Program which relies entirely upon biomass including landfill gas, and the company is implementing as part of its IRP a conservation and energy efficiency program.[97] Finally, the GA PSC has adjudicated both base rate and fuel adjustment clause applications, including approval of an environmental compliance cost recovery tariff that provides for recovery of projected, post test-year environmental compliance costs.[98]

E. Louisiana

The Louisiana Public Service Commission (LPSC) issued three major orders affecting electric utility rates and infrastructure development. First, on August 1, 2007, in Re Energy Gulf States and Entergy Louisiana,[99] it tackled an array of issues triggered by the heavy toll taken by Hurricanes Katrina and Rita (which swept through the region in August and September of 2005) on these two systems' transmission and distribution assets, authorizing based on a negotiated settlement total reconstruction cost recovery for the two companies of $732 million and establishment of a future reserve of $339 million. To procure low-cost, long-term financing of these large, upfront system repair costs, the LPSC authorized "securitization" – *i.e.*, issuance of highly rated bonds secured by the cashflow from dedicated ratepayer payments over time, which it estimated would produce $271 million of savings as compared to alternative financing approaches. The LPSC concluded that it would be inappropriate for any class to avoid large portions of storm-related costs or reserves despite an argument from industrials served only by the largely undamaged transmission system that their service did not require the reconstruction, and allocated the costs to all groups according to their "base revenue contribution."[100]

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95. Press Release, GA PSC, PSC Approves Agreement to Allow Construction of New Units at Vogtle Nuclear Power Generation Plant (March 17, 2009); In re Georgia Power's Application for the Certification of Units 3 and 4 at Plant Vogtle, Docket No. 27800 (GA PSC 2009).

96. *Id.*

97. Georgia Power Co.'s Application For Approval of its 2007 Integrated Resource Plan, Docket No. 24505-U (GA PSC 2007); Press Release, GA PSC, PSC Approves Revamped Georgia Power Green Energy Program (Sept. 15, 2008).

98. Georgia Power Co., 262 P.U.R.4th 198 (GA PSC 2007).

99. Order No. U-29203-B. The securitized financing was also authorized by act of the state legislature.

100. As a concession, however, to the argument that transmission-level customers should *not* be responsible for rehabilitation of the distribution system, the LPSC reduced by 50% the distribution facilities cost allocation that otherwise would apply to them.

In the first of two major orders addressing the state's need for a more fuel-diverse generation mix the LSPC, on March 19, 2008, ruled on Entergy Louisiana's request for certification of a "repowering" project – one that would convert its gas-fired Little Gypsy Unit 3 to a solid fuel, 538 MW generator (designed to burn a coal/petroleum coke mix), at a total cost of about $1.5 billion (including pre-operational financing costs).[101] The plant's dispatch profile would also be modified from peaking to baseload usage. Under the LPSC's new unit certification rules, Entergy Louisiana had to demonstrate not only the prudence and cost-effectiveness of the selected option,[102] but also that it had compared the Little Gypsy self-build route to third-party supply options identified through an RFP process. The LPSC certificated the Little Gypsy 3 repowering project, subject to a prudent execution obligation and a list of ten assorted conditions negotiated between the company and the staff.[103] One month later, the LPSC certified construction of a 600 MW, ultra-super-critical coal-fired plant estimated to cost $1.4 billion to be undertaken by Southwestern Electric Power Co. (SWEPCO).[104] The SWEPCO facility (known as the "Turk Plant") is a greenfield project to be built in Hempstead Co., Arkansas, requiring approval by several states in which SWEPCO serves (Texas, Arkansas, and Louisiana). The LPSC found that the proposed project was needed from a load growth and fuel diversification standpoint; however, its approval was made subject to a long list of conditions, some of which paralleled those in the Little Gypsy certification case while others reflected the multi-owner, multi-jurisdictional character of SWEPCO's project. While both the Texas and Arkansas utility regulatory commissions approved the SWEPCO project, the Arkansas Court of Appeals concluded, in a June 2009 decision, that the APSC had misconstrued its statute in dividing its certification review into multiple phases and remanded the decision.[105]

F. Mississippi

The January 19, 2009 application of Mississippi Power Company (MPC) to construct a state-of-the-art, 582-MW integrated gasification combined-cycle (IGCC) plant,[106] using locally mined lignite to be gasified as the fuel input, ran into stiff opposition from the State's Attorney General and the Sierra Club. The

101. In re Entergy Louisiana, L.L.C., Order No. U-30192 (LPSC 2008).

102. The application explained that Entergy Louisiana looked at several technologies and determined that the circulating fluidized bed approach, which facilitates reductions in sulfur dioxide and NOX emissions, was preferable, and was ideally suited to using local petroleum coke (a byproduct of oil refineries in the region). *Id*.

103. Among these were further study of energy efficiency opportunities in cooperation with the Staff. a study of the feasibility of carbon capture should legislation be enacted regulating carbon emissions, and review of whether an allocation of some portion of the plant to sister company Entergy Gulf States – Louisiana would be in the public interest. *Id.*

104. Southwestern Electric Power Co. Order Nos. U-29702 and 27866 (LA PSC 2008). The order contained the understanding that SWEPCO's ownership stake in the Hempstead Co. facility would be fixed at 73% (440 MW).

105. *See* "Arkansas" section of this report for more details on the Court of Appeals decision.

106. The plant, costing an estimated $2.5 billion, would be designed to remove 50% of the carbon emissions for injection into oil wells to enhance recovery. The U.S. DOE is evaluating the project for a potential cash contribution.

Mississippi Public Service Commission (MPSC), rather than either staying the proceeding (as the opponents requested) or giving it expedited review, issued a June 5 order dividing the proceeding into two phases.[107] The first phase would focus on the need for the additional capacity, taking into account the demand-dampening effects of current conservation and rate design initiatives. If the analysis in the first phase confirms the need for the additional baseload capacity, then Phase Two would compare the IGCC plant proposal to other options (*e.g.*, another type of utility-built plant, purchased power, and demand resource development). The MPSC order included a case schedule envisioning a decision on Phase One by October 2009 and on Phase Two by May 2010. The Attorney General also crossed swords with the State's other major investor-owned system, Entergy Mississippi. In December 2008, he filed a lawsuit in a state court accusing the Entergy affiliate of "routinely" manipulating power and fuel purchases in its dealings with other Entergy affiliates, costing Mississippi ratepayers "millions of dollars" that should be refunded. He linked Entergy Mississippi's conduct to allegedly similar activities in Louisiana and Texas that resulted in lawsuits and refunds of "over $100 million," as he asserted in a news conference. One pattern the lawsuit criticized as an example of unlawful cost "padding" involved procuring surplus power from affiliated Entergy companies when less costly power could have been purchased in the open market. The MPSC joined in the fray by issuing a November 24 "resolution" requesting Entergy Mississippi to provide information the Attorney General was seeking. Entergy Mississippi countered that the Attorney General was on a "fishing expedition" and requested the MPSC to open a formal docket to investigate the matter in the exercise of its own jurisdiction, instead of facilitating the Attorney General's lawsuit.[108] Although Entergy Mississippi denied the underlying claims in December, it acknowledged in a letter to the MPSC in January that Entergy Mississippi's customers "may have been adversely affected" by some of the activities in Louisiana that had resulted in the large refunds to ratepayers. It has not as yet quantified the impact.[109]

G. North Carolina

North Carolina has adopted significant legislation impacting on state utility regulation in recent years. Session Law 2007-397 adopts the South's only mandatory Renewable Energy and Energy Efficiency Portfolio Standard. Renewable energy supply requirements under the standard begin at three percent in 2011 and grow to 12.5% by 2020 for Investor Owned Utilities. Renewable energy supply that may be counted toward the requirement includes solar, methane produced from swine and poultry waste, biomass, energy efficiency and certain other technologies. A number of formal hearings and reports were devoted to initiating the program in 2008 & 2009.[110] The North Carolina Public

107. Petition of Mississippi Power Co. for a Certificate of Public Convenience and Necessity, No. 2009-UA-14 (MS PSC 2009).

108. Housley Carr, *Mississippi AG files Lawsuit accusing Entergy of Profit Padding Manipulation, Deception*, POWER MARKETS WEEK, Dec. 8, 2009, at 11.

109. Entergy Mississippi May Have Erred in PSC Filings, ELECTRIC POWER DAILY, Jan. 9, 2009, at 1.

110. Rulemaking Proceeding to Implement Sess. Law 2007-397, No. E-100, Sub 113 (NC PUC 2008); Swine Farm Methane Capture Pilot Program, Sess. Law 2007-523 (2009); Annual Report Regarding

Utilities Commission also issued several Certification of Need Orders approving the construction of regulated utility proposed nuclear, coal and natural gas fired plant construction. These Orders approved plant construction and incurrence of early development costs, but did not allow rate recovery prior to operation of such costs nor provide assurance that costs would ultimately be allowed rate recovery.[111] Certificates of Need have also been requested for an innovative, distributed solar photo-voltaic program pursuant to which Duke Power will own and install 10 MW of such equipment at several hundred customer premises and recover its investments and costs in rates, and a 16 MW central station solar plant.[112] There has also been established the North Carolina Transmission Planning Collaborative, a state-wide planning group comprising all significant transmission owning entities in North Carolina, who develop and implement, in cooperation with the NC PUC, a 10 year transmission plan. The most recent Plan (i.e. 2007) proposes development of some seventeen separate major transmission improvement projects with a cost of $400 million.[113] Also, Duke Power is seeking NC PUC approval of a major energy conservation program which it has called "Save-a-Watt". The program is proposed due to the significant growth in electric energy requirements in its service territory, such that Duke expects to require 3,400 MW of incremental capacity over 2008 levels by 2012. As much as 1,860 MW of this projected capacity requirement is believed avoidable through "Save-a-Watt" and at costs below that of adding new capacity. The program, however, is being strongly opposed by consumer groups as Duke proposes to recover ninety percent of the costs of the program (including a return on investments) through a dedicated surcharge rider.[114]

Finally, a number of rate applications (both fossil adjustment clause and base rates) have been or are pending to be adjudicated during the period, with the most significant being Duke's first base rate application in twenty years (i.e. a 12.6%/$496 million request).[115] In a further rate related matter, the NC PUC has denied a request by Duke to provide wholesale service to a South Carolina municipal utility not located in its control area at Duke's system average cost, concluding that to do so would injure native load customers, and providing that such service must be provided at incremental cost. The latter prevents Duke from displacing the municipal's historic provider who is permitted to continue

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Renewable Energy and Energy Efficiency Portfolio Standard in North Carolina (NC PUC 2008); NC PUC, REPORT REGARDING AN ANALYSIS OF RATE STRUCTURES, POLICIES AND MEASURES TO PROMOTE RENEWABLE ENERGY GENERATION AND DEMAND REDUCTION IN NORTH CAROLINA (NC PUC 2008); NC PUC & NC DENR, JOINT REPORT ON THE IMPLEMENTATION OF THE SWINE FARM METHANE CAPTURE PILOT PROGRAM (January 2009).

111. Duke Energy Carolinas, L.L.C., No. E-7, Sub 909 (NC PUC 2009); Duke Energy Carolinas, L.L.C., 265 P.U.R. 4th (NC PUC 2008); Duke Energy Carolinas, L.L.C., No. E-7, Sub 819 (NC PUC 2008).

112. Housley Carr, *Duke scales Back Solar Plans in North Carolina*, ELECTRIC POWER DAILY, at 7 (Oct. 24, 2008); *Duke Energy Announces Pact to Harness the Power of the Sun*, PR NEWSWIRE, May 21, 2008.

113. *Collaborative Major Transmission Plan IDs Major Projects*, PR NEWSWIRE, Jan. 24, 2008; *North Carolina Transmission Planning Collaborative*, ENERGY & ECOLOGY, June 16, 2008, at 164.

114. In re Sav-a-Watt Approach, Energy Efficiency Rider and Portfolio of Energy Efficiency Programs, Docket E-7, Sub 831 (NC PUC 2009).

115. *See, e.g.*, Piedmont Natural Gas Co., Inc., 269 P.U.R.4th 320 (NC PUC 2008); *Duke Energy Cites Future GHG Cap in Move to Higher Electricity Rates*, 6 ENERGY WASHINGTON WEEK 25, June 24, 2009, *available at* www.energywashington.com/; In the Matter of Dominion North Carolina Power, Docket E-22, Sub 451 (NC PUC 2008).

service at its average service cost which is lower than Duke's incremental cost.[116]

H. South Carolina

In 2007, South Carolina enacted the Base Load Review Act.[117] Pursuant to its terms, a utility, having received approval from the South Carolina Public Service Commission (SC PSC) to construct base load generation, can obtain financing and cost recovery for a plant during its construction. Both Investor and State owned utilities, i.e. South Carolina Gas (SCG&E) & Electric, Duke, and Santee Cooper, have sought and obtained such approval for nuclear power plant construction (i.e. Lee & Sumner). SCG&E has filed for SC PSC approval of a financing plan in rates during construction, proposing roughly 2.5% general rate increases for this purpose each of the next ten years.[118] The SC PSC also adjudicated two requests for approval of DSM & energy efficiency programs, including a cost recovery tariff rider, approving that of Progress Energy and denying that of Duke Energy Carolinas. Progress program is designed to reduce peak load in its service territory by approximately 1000 MW, while permitting it to recover its costs and a return on investments as well as to retain eight percent of the net benefits of DSM programs and thirteen percent of the net benefits of energy efficiency programs as an incentive to assure aggressive pursuit of the program. Duke's program was rejected as the incentive features were viewed as unduly favorable to Duke, but the Company was urged to return and file a more balanced program as soon as possible.[119]

I. Virginia

Virginia is the only state in the region which restructured its electric industry and sought to create a competitive retail market. However, after six years in which only very limited interest was shown in this Virginia retail market by both end-use customers and competitive suppliers, in 2007, the General Assembly adopted legislation effectively re-regulating the market for all but customers with a demand level exceeding 5 MW and in certain situations of permitted load aggregation.[120] Obligations to provide non-discriminatory

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116. In the Matter of Duke Energy Carolinas, L.L.C.'s Advance Notice of Power Purchase Agreement with the City of Orangeburg, Docket E-7, Sub 858 (NC PUC 2009); In the Matter of Duke Energy Carolinas, L.L.C.'s Advance Notice of Power Purchase Agreement with the City of Greenwood, Docket E-7, Sub 866 (NC PUC 2009).

117. 2007 S.C. Acts 16.

118. In the Matter of Duke Energy Carolinas, L.L.C., Docket 2007-440-E (SC PSC 2007); In the Matter of South Carolina Electric & Gas Co., Docket 2008-196-E (SC PSC 2009); Housley Carr, *Santee Cooper to Raise Rates Over Three Years to Pay for New Nuclear, Coal-Fired Capacity***,** ELECTRIC UTILITY WEEK, Dec. 15, 2008, at 22; Tom Harrison, *SCE&G Seeks Approval for Financing New Units*, 49 NUCLEONICS WEEK 23 (2008); SC PSC, *Nuclear Power Applications at the PSC*, 4 PSCNEWS 1, at 1 (2008). SCG&E states that permitting financing during construction will reduce the cost of the two unit plant to ratepayers by as much as $4 billion. SCPSC approval of the construction of Sumner remains subject to reconsideration and has been appealed.

119. In re Application of Carolina Power & Light Co. for the Establishment of Procedures for DSM/EE Programs, Docket 2008-251-E (SC PSC 2009); In re Application of Duke Energy Carolinas, L.L.C. for Application of Energy Efficiency Plan, Docket 2007-358-E, Order 2009-109 (SC PSC 2009).

120. 2007 Virginia Laws Ch. 888 (H.B. 3068); 2007 Virginia Laws Ch. 933 (S.B. 1416) Customers are still permitted to aggregate load, including municipal aggregation, subject to approval by the Virginia

transmission and distribution service, to join or establish an RTO and functional unbundling requirements were not repealed.[121] Capped retail rates established to facilitate transition to the competitive retail market expired on December 31, 2008, but cannot be altered until completion of retail rate proceedings before the Virginia Corporation Commission (VCC) to be initiated in early 2009. A number of base and fuel adjustment rate applications have been filed under the new statute, and either have or are in the process of adjudication.[122] The statute contains a number of interesting provisions respecting future rate standards, including specification that rates for different services are to be reviewed separately and that separate fair returns and a combined return are to be established for generation and distribution services, a biennial review of rate levels, required use of a Southeastern electric utility peer group to establish a fair rate of return, allowance of a fifty basis point collar before existing rates are to be adjusted (i.e. rates are only to be adjusted if the earned return is more than fifty basis points above or below that found to be fair) and rewards or incentives are provided for good operating performance or undertaking certain new supply construction activities.[123] As respects operating experience, the VCC is authorized to reward good "generating plant performance, customer service and operating efficiency" as compared to national standards with a 100 basis point addition to the fair return otherwise permitted.

As respects new generation supply, a 200 basis point addition may be granted. Also, utilities are permitted to request the adoption of rate adjustment clauses to assure recovery of costs associated with coal-fuel generation able to utilize Virginia coal, other new generation development and major modifications to existing generation facilities.[124] A voluntary renewable energy portfolio standard is adopted which calls for twelve percent renewable supply sourcing by 2022, though it permits participation at lower levels, and provides assurance of cost recovery to pursue the program. A goal of reducing electric energy consumption of retail customers by ten percent by 2022 is also adopted, and the

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Corporation Commission (VCC) and thereby obtain non-regulated service. Customers who take advantage of this remaining competitive option are not permitted to return to regulated service until after a five year written notice period has expired unless an exemption is granted by the VCC. VA CODE ANN. §§ 56-577 & 56-589 (2009).

121. VA CODE ANN. §§ 56-578, 56-579 & 56-590 (2009).

122. VA CODE ANN. §§ 56-582 & 56-585.1 (2009). The VCC has adopted new regulations governing these cases. In re Revised Utility Rate Case Rules, No. PUE-2008-00001 (VCC 2008). Also see In re Appalachian Power Co, No. PUR-2009-00038 (VCC 2009); In re Dominion Virginia Power, No. PUE-2009-00019 (VCC 2009); In re Appalachian Power Co., No. PUE-2008-00046 (VCC 2008); In re Appalachian Power Co., No. PUE-2008-00067 (VCC 2008). The VCC has approved an environmental and reliability surcharge requested by Appalachian Power, and adjustment clauses to permit recovery of generation construction costs for Dominion Virginia Power. *See* Appalachian Power Co., No. PUE-2008-00045 (VCC 2008); Dominion Virginia Power, Nos. PUE-2009-00017 (Bear Garden) & No. PUE-2009-00011 (Virginia City Hybrid Energy Center)(2009).

123. VA. CODE ANN. § 56-585.1 (2009).

124. VA. CODE ANN. § 56-585.1A6 (2009). Allowances for construction work in progress, in addition to development cost recovery and an incentive rate of return, are allowed. The incentive rate of return is allowed for nuclear, coal, natural gas combined cycle and renewable powered generation, both during construction and for a period thereafter which varies by fuel type for up to 25 years. Incentives related to new generation development may reflect the fact that Virginia is often indicated in the trade press to be the state with the second highest import of electric supply to meet its native load. *See* 32 PLATTS COAL OUTLOOK 14, at 5 (April 7, 2008).

VCC is instructed to study and report on how the goal can be achieved. A requirement for the development of Integrated Resource Plans beginning by December 31, 2008 was also adopted, and the VCC has adopted implementing regulations and has ordered that such plans be prepared and filed with it by September 1, 2009.[125] The VCC adjudicated a number of generation certification applications during the past 18 months, approving all but one. These decisions were necessitated and issued following adoption of the 2007 "re-regulation" law which reestablished the requirement for a certification of need before new generation could be constructed by a regulated utility in the Commonwealth.[126] In April 2008, the VCC granted a certificate permitting construction of Dominion Virginia Power's (DVP) 585 MW Virginia City Hybrid Plant, a circulating fluidized bed coal-fired plant in Southwest Virginia, including approval of a 100 basis point incentive return allowance during construction and for the first twelve years of plant operation. The plant will be able to burn both Virginia coal and biomass (i.e up to twenty percent of fuel used), and has an approved cost of $1.8 billion. Any cost incurred above that level will be reviewed for prudence and necessity in a future proceeding. DVP has also obtained approval for construction of the 580 MW Bear Garden natural gas fired, combined cycle plant in central Virginia.[127] The VCC, however, rejected certifying a proposed 629 MW coal-fired IGCC plant proposed by Appalachian Power for construction in West Virginia to serve customers in both jurisdictions. The VCC found that the economic risk posed by the technology to be used at the plant, which has not previously been constructed or operated at this size and with planned carbon capture, was too great and could not be prudently imposed on ratepayers.[128]

Throughout the period covered by this report, the SCC acted favorably on applications to construct major transmission system enhancements planned to alleviate reliability concerns in Northern and Southeast Virginia. On October 7, 2008, the VCC conditionally authorized DVP to construct the sixty-five mile Northern Virginia segment of a 240-mile, 500 kV project traversing three states (including W. Virginia and Pennsylvania), part of a joint venture between DVP and the Trans-Allegheny Interstate Line Co. (an affiliate of Allegheny Power).[129] Besides finding that the project was an appropriate response to avoid reliability violations as soon as 2011, the SCC rejected an intervener position that, prior to approval, the project must be compared to alternatives—such as generation, demand response, and conservation explaining that it is PJM that is charged with regional transmission planning under Federal law.[130] The SCC's approval was

125. VA. CODE ANN. §§ 56-585.2, 56-594 & §§ 56-597 – 599 (2009); Re Guidelines for Developing Electric Utility Integrated Resource Plans, Case PUE-2008-00099 (VCC 2008).

126. VA. CODE ANN. § 56-580D (2009); In re Revised Rules for Applications to Construct and Operate Electric Generating Facilities, No. PUE-2008-00066 (VCC 2008).

127. In re Dominion Virginia Power, No. PUE-2007-00066 (VCC 2008). The VCC's Order granting certification of the coal plant has been appealed.

128. In re Appalachian Power Co., 264 P.U.R.4th 308 (VCC 2008); In re Appalachian Power Co., 265 P.U.R.4th 173 (VCC 2008).

129. In re Virginia Electric and Power Co., d/b/a Dominion Virginia Power, Nos. PUE-2007-00031 and -00033 (VCC 2008).

130. At the same time, the SCC remarked that it was "indeed sympathetic" to the position that transmission, generation, and conservation options *should* be considered in an "integrated and holistic fashion."

explicitly conditioned on approval by its counterparts in the two other states the project would cross. In separate proceedings, the SCC approved (1) on February 15, 2008, construction of a 12-mile, 230 kV overhead line (also in Northern Virginia's Loudon County);[131] (2) on October 31, 2008, construction of an eighty-two mile project (about three-quarters of which would be 500 kV, the rest 230 kV) to address reliability concerns in Southeastern Virginia;[132] and (3) on April 8, 2008, a five mile, 230 kV line in Central Virginia's Stafford County.[133] The Stafford line and a portion of the twelve mile Loudon line were approved for underground construction using XLPE cable pursuant to an experimental program authorized in 2008 by the state legislature.[134]

In other developments, the SCC by rulemaking amended, in response to a new legislative directive,[135] its "net metering" regulations (allowing distribution system customers to sell any "net" self-generation in excess of their loads back to the utility at a price determined by the SCC (which it set at the zonal PJM Locational Marginal Price, or LMP).[136] In the realm of territorial acquisition, two Virginia cooperatives – Rappahannock Electric and Shenandoah Valley – in May 2009 agreed to purchase Potomac Edison's distribution operations in Virginia for $340 million. Late in 2007, a second of Virginia's then four investor owned utilities, Delmarva Power & Light, transferred its service territory to a third cooperative – A & N.[137] Finally, in August 2008, Appalachian Power Co. (APCO) received approval of its application to participate in the statutory (but voluntary) RPS incentive program.[138] Under the program, a utility is entitled to recover its incremental costs plus a fifty basis point premium to its return on equity if it complies with goals of meeting specified levels of electricity sales with renewable generation sources – beginning in the first year (2010) with four percent and escalating to twelve percent in 2022. On December 3, 2008, the SCC approved another voluntary "green power" program for retail customers proposed by Dominion Virginia Power and APCO.[139] The SCC viewed the companies' proposed concept of purchasing and "retiring" renewable energy credits (RECs) – essentially vouchers that can be disassociated from their producing power source—as something *other* than selling actual renewable energy.[140] The practical consequence was that retailers other than the incumbent

131. In re Virginia Electric and Power Co., d/b/a Dominion Virginia Power, Nos. PUE-2005-00018 (VCC 2008).

132. Virginia Electric and Power Co., d/b/a Dominion Virginia Power, Nos. PUE-2007-00020 (VCC 2008).

133. Virginia Electric and Power Co., d/b/a Dominion Virginia Power, Nos. PUE-2006-00091 (VCC 2008).

134. H.B. 1319 Gen. Assem. (Va. 2008).

135. 2007 Acts of Assem. Chaps. 877, 888 and 933, amending VA. CODE §56-594.

136. In re Net Energy Metering, No. PUE-2008-0008 (VCC 2008).

137. *REC Acquisition Could Lower Bills*, THE FREE-LANCE STAR, May 15, 2009; Press Release, VCC, SCC Approves A&N Electric Cooperative Purchase Of Delmarva Power's Eastern Shore Service Territory (Oct. 19, 2007).

138. VA. CODE § 56-585.2; Appalachian Power Co., No. PUE-2008-00003 (VCC 2008).

139. Appalachian Power Co., No. PUE-2008-00057 (VCC 2008).

140. *Id.* at 13-16.

could also sell "green" energy in the companies' respective territories.[141] In 2008, the Virginia General Assembly adopted the Natural Gas Conservation and Ratemaking Efficiency Act which encourages natural gas utilities to develop and file for VCC approval formal Conservation and Ratemaking Efficiency Plans.[142] These plans are to include conservation programs that improve the efficiency of natural gas service to residential and small commercial customers, and may also include revenue decoupling mechanisms.[143] Two such plans have been filed under the statute (Virginia Natural Gas & Columbia Gas), and that of Virginia Natural Gas (which includes a revenue decoupling mechanism) has been approved by the VCC.[144]

J. West Virginia

Allegheny Power's wholly owned subsidiary, TrAILCo, requested the Public Service Commission of West Virginia (PSCWV), in a March 2008 filing, to certificate a 500 kV transmission line whose Pennsylvania-West Virginia-Virginia footprint would pass through six counties of West Virginia, comprising some 114 miles.[145] The TrAILCo Project had been planned and approved by the PJM Regional Transmission Organization (RTO) as integral to meeting regional reliability criteria in the 2011 timeframe.[146] It presented PSCWV with the dilemma that, while reliability or "market efficiency" needs—and solutions—for the interstate power system tend to be regional in nature, environmental impacts are mainly local.[147] The West Virginia certification statute did, however, expressly direct the PSCWV to consider regional as well as local needs.[148] Refusing to take what it called an "isolationist" viewpoint, the PSCWV found, in its August 1, 2008 order,[149] that state law and policy favor both the "export" of locally generated power and the related construction of transmission facilities to enhance exports. The opinion also dwells on PJM's "core role" as regional planner, stressing its duty to meet the federally-enforced NERC reliability standards that require the line's construction.[150] The PSCWV concluded that the evidence supported (a) the demonstrable need for such a facility to avoid impending violations of reliability criteria[151]; (b) the conclusion that, while the project was devised to accommodate load growth in PJM's mid-Atlantic load centers, West Virginia reliability would be adversely affected if the project were to be rejected or deferred[152]; (c) the lack of alternatives (such as generation or

141. Va. Electric & Power Co., No. PUE-2008-00044(VCC 2008); Appalachian Power Co., No. PUE-2008-00057 (VCC 2008).

142. VA. CODE ANN. §§ 56-600-03 (2009).

143. *Id.* at § 56-602.

144. Va. Natural Gas, Inc., No. PUE-2008-00060(VCC 2008); Columbia Gas of Va., Inc., No. PUE-2009-00051(VCC 2009).

145. Trans-Allegheny Interstate Line Co., No. 07-0508-E-CN (WV PSC 2008), *available at* www.psc.state.wv.us/scripts/WebDocket/ViewDocument.cfm?CaseActivityID=245762.

146. *Id.* at 95-96

147. *Id.* at 56.

148. W. VA. CODE §24-2-11a(d)(1) (2009).

149. Trans-Allegheny Interstate Line Co., *supra* note 146.

150. *Id.* at 12.

151. *Id.* at 125.

152. *Id.* at 122-23.

demand response) that Allegheny could count on to resolve the risk to reliability[153]; and (d) the balance struck between environmental and energy considerations[154].

In re Appalachian Power Company, WVPSC made findings of need, economic benefit, no alternative renewable or efficiency solution and environmental advantage from certification and construction of Appalachian's proposed IGCC plant in Mason County, West Virginia.[155] One issue presented by Interveners opposing certification was whether carbon capture and sequestration should be required.[156] The Commission rejected this proposal, concluding that:

Until APCO knows what the carbon emission regulations will be, the Commission agrees it will be difficult to determine what level of carbon capture will be needed and how to accomplish it in the most economical fashion. Accordingly, the Commission will not require APCO to make the Project carbon capture compatible, as opposed to carbon capture capable, at this time. APCO should understand, however, that the Commission supports carbon capture for all the reasons discussed herein, including particularly the ability to commit to use West Virginia coal and to vary the coal mix for the Plant.[157]

The WVPSC has also been required to adjudicate several large rate and fuel cost proceedings during the reporting period due to rising fossil fuel costs employed at the State's generation plants.[158] On November 26, 2008, the PSCWV issued an order certificating a $250 million AES wind energy project, Laurel Mountain Windpower, subject to fulfilling an assortment of conditions before, during, and after the course of construction.[159] The order hailed the tax revenue dividends represented by the project, projected to be $450,000/year to the involved counties and $350,000 to the state.[160] While opponents challenged the project as creating unacceptable views, noise, and wildlife impacts, the PSCWV found these impacts manageable, while also dispelling claims that the project's power would not be needed by PJM.[161]

153. *Id.* at 125.

154. *Id.* at 127-129.

155. Appalachian Power Co., No. 06-0033-E-CN(WV PSC 2008); 263 PUR 4th 297 (WV PSC 2008); responding to Virginia's failure to certificate the Plant, WV PSC has withdrawn for now its certification, Appalachian Power Co., No. 06-0033-E-CN (WV PSC 2009), *available at* www.psc.state.wv.us/scripts/WebDocket/ViewDocument/cfm?CaseActivityID=278931.

156. *Id.* at 15.

157. *Id.* at 75.

158. Monongahela Power Co., No. 08-1511-E-GI (WV PSC 2008), *available at* www.psc.state.wv.us/scripts/WebDocket/ViewDocument.cfm?CaseActivityID=256439; Appalachian Power Co., No. 08-0278-E-GI (WV PSC 2008), *available at* www.psc.state.wv.us/scripts/WebCocket/ViewDocument.cfm?CaseActivityID=243010; Appalachian Power Co., No. 09-0177-E-GI (WV PSC 2009), *available at* www.psc.state.wv.us/scripts/WebDocket/ViewDocument.cfm?CaseActivityID=28007.

159. AES Laurel Mountain, L.L.C., No. 08-0109-E-CS (WV PSC 2008), *available at* www.psc.state.wv.us/scripts/WebDocket/ViewDocument.cfm?CaseActivityID=254448. The project would span 8 miles of ridgeline with some 65 turbines, expected to have a cumulative capacity of 125-132 MW. *Id.* at 52-53, 72-77.

160. *Id.* at 53.

161. *Id.* at 65, 76.

IV. MID-WESTERN REGION

The Midwest region (thirteen states) saw a high level of legislative activity during the 2008 and 2009 sessions. In the three retail competition states, Ohio, Michigan, and Illinois, legislatures revised restructuring schemes. In Minnesota, Missouri, and Nebraska, they addressed renewable energy, energy efficiency, and other issues. One major merger was completed (between KCP&L and Aquila).[162] Major transmission siting decisions were reported in Wisconsin, Minnesota, South Dakota, and Kansas. Generating plant approvals were noted in Indiana, Wisconsin, North Dakota, South Dakota, and Minnesota. South Dakota approved siting of a major oil pipeline.[163]

A. Illinois

On May 31, 2009, the Illinois General Assembly passed Senate Bill 1918.[164] Proponents state that SB 1918 promotes progressive regulatory policy, helps low-income utility customers, and advances energy efficiency.[165] SB 1918 allows incremental bad debt adjustments annually to ensure customers pay the exact amount of bad debt a utility incurs.[166] It also sets a percentage-of-income payment plan (PIPP) that helps low-income households, including seniors and those with disabilities, manage their utility bills and break the cycle of disconnections and reconnections.[167] Under this plan, participating customers will pay no more than six percent of their income and will use their Low-Income Home Energy Assistance Program (LIHEAP) benefits to maintain affordable year-round utility services.[168] The bill establishes an energy efficiency program for natural gas utilities. Under new Sec. 8-104 of the PUA, the value of electric energy savings is to be taken into account when computing benefit/cost of gas efficiency programs and vice versa.[169] The bill also amends the Electric Service Customer Choice and Rate Relief Law of 1997 in the Public Utilities Act to provide that an alternative retail electric supplier (ARES) shall be responsible for procuring cost-effective renewable energy resources as required under specified provisions of the Act in a specified manner.[170] The bill was sent to Governor Pat Quinn for his signature.

HB 0722 repeals Section 17-800 of the Public Utilities Act and transfers the authorizations for county and municipal load aggregation to the Illinois Power Agency (IPA) Act along with imposing on the IPA the obligations originally

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162. Great Plains Energy, Inc., No EM-2007-0374 (MO PSC 2008).

163. TransCanada Keystone Pipeline, No. HP07-001 (SD PUC 2008), *available at* http://puc.sd.gov/commission/orders/HydrocarbonPipeline/s008/hp07-001.pdf.

164. Bill Status of S.B. 1918, www.ilga.gov/legislation/billstatus.asp?DocNum=1918&GAID=10&GA=96&DocTypeID=SB&LegID=44807&SessionID=76 (last visited Oct. 10, 2009).

165. Press Release, Office of Governor Pat Quinn, Governor Quinn Signs Bill to Aid Tens of Thousands of Low Income Utility Customers (July 10, 2009), available at http://www.illinoisattorneygeneral.gov/pressroom/2009_07/07.10.09_GOV_SB1918_Signing_LIHEAP.pdf.

166. Ill. S.B. 1918 (2009)

167. *Id*. at 107-115.

168. *Id*.

169. *Id*. at 26-27.

170. *Id*. at 27.

imposed on the Illinois Commerce Commission.[171] The bill authorizes customer load aggregation and power procurement planning for residential and small commercial retail customers by county and municipal governments and imposes on the IPA the obligation to review and approve those plans and activities. The bill imposes different obligations on county and municipal governments depending upon whether they desire to operate an opt-in or opt-out aggregation, requiring, for example, that if the county or municipal government desires to operate an opt-out aggregation program, they must receive approval through a referendum about that program in each municipality or county that is to be part of the aggregation, while a referendum is not required for an opt-in aggregation program. The bill imposes on the IPA certain enumerated obligations regarding county and municipal aggregation and power procurement plans. On June 11, 2009, the House sent this bill to the Governor to be signed.[172]

HB 3854 creates the Illinois Energy to Jobs Act, establishes renewable energy production districts, deletes language in existing statutes concerning a moratorium on the construction of nuclear power plants, and amends numerous other acts:

(1) the IPA Act to make changes concerning the Resource Development Bureau and in the definition of an "energy facility";

(2) the IPA Act to allow the Agency to acquire by eminent domain permanent easements for the distribution, transportation, and storage of CO_2;

(3) the IPA Act and Public Utilities Act to make changes concerning the prudence of supply contracts;

(4) statutes concerning certificates of Good standing for common carriers by pipelines;

(5) the State Fire Marshal Act, the Environmental Protection Act, the IPA Act, and the Public Utilities Act providing that there shall be processes for expediting the issuance of permits and licenses for projects at energy facilities;

(6) the Illinois Income Tax Act, the Use Tax Act, the Service Use Tax Act, the Service Occupation Tax Act, and the Retailers' Occupation Tax Act to restore specified tax exemptions beginning on the effective date of the amendatory Act;

(7) the Department of Commerce and Economic Opportunity Law concerning financial assistance and to the Illinois Enterprise Free Zone Act concerning high impact businesses;

(8) the Property Tax Code to add a provision concerning real property taxes at energy facilities;

(9) the Eminent Domain Act to make conforming changes.

The bill also creates a Carbon Capture and Sequestration Legislation Commission.[173] This commission would be charged with issuing a report to the

171. Ill. H.B. 0722 (2009).

172. Bill Status of H.B. 3854, www.ilga.gov/legislation/billstatus.asp?DocNum=3854&GAID=10&GA=96&DocTypeID=HB&LegID=46670&SessionID=76 (last visited Oct. 10, 2009).

173. Ill. H.B. 3854 (2009).

General Assembly by December 31, 2010 on all issues deemed appropriate to carbon capture and sequestration legislation.[174] On June 26, 2009, the House sent this bill to the Governor to sign.[175]

SB 1140 declares that any residential or non-residential customer shall not be deemed ineligible to receive rate relief pursuant to Section 16-111.5A solely based upon the customer's purchase of electricity from a supplier other than the electric utility.[176] On June 16, 2009, the Senate sent this bill to the Governor.[177]

In the U.S. Court of Appeals for the Seventh Circuit, the ICC petitioned the court for review of the FERC order socializing costs of new high voltage transmission facilities 500 kV and over without a showing of cost causation of or benefits to those allocated costs. Oral Argument was held on April 13, 2009. In its decision on August 6, 2009, the Court granted the ICC and Ohio PUC petitions to overturn the FERC cost allocation for new transmission facilities 500 kV and above, and remanded for further proceedings.[178] The Court denied AEP's petition to shift sunk costs to existing facilities to other PJM members.

B. Indiana

In Cause No. 43114-IGGC-1,[179] the Indiana Utility Regulatory Commission approved Duke Energy's updated $2.350 billion estimated construction cost for Duke's IGCC Project and the ongoing review progress report concerning the IGCC. Duke Energy had asked the Commission to approve the plant's higher cost, saying the project's estimated price tag had risen $365 million, to $2.35 billion, largely due to the rising costs of materials and labor. The 630-megawatt plant is estimated to result in an eighteen percent rate increase for its customers phased in over the next five years. In addition, the incentive treatment of deferred income taxes approved in the Commission's previous order was limited to the initial $1.985 billion estimate presented by the company. The Company's request to extend the incentive treatment to the $2.350 billion estimate was denied. In Cause No. 43665,[180] a related cause, Duke Energy has requested an alternative regulatory plan for approval of and cost recovery associated with the study of carbon storage for the Edwardsport IGCC project. This matter is pending. In Cause No. 43566,[181] the Commission denied industrial interveners' request for an interim order authorizing otherwise qualified entities to take any and all steps and actions required to register for and participate directly in PJM's demand response programs. In its denial, the Commission said that its

174. *Id.*

175. Bill Status of H.B. 0722, www.ilga.gov/legislation/publicacts/96/PDF/096-0176.pdf (last visited Oct. 10, 2009).

176. Ill. S.B. 1140 (2009).

177. Bill Status of SB 1140, www.ilga.gov/legislation/billstatus.asp?DocNum=1140&GAID=10&GA=96&DocTypeID=SB&LegID=42053&SessionID=76 (last visited Oct. 10, 2009).

178. Illinois Commerce Commission, et al. v. FERC, 576 F.3d 470 (7th Cir. 2009).

179. Duke Energy Indiana, No. 431141IGCC 1, (IN URC 2009), seeking authority to reflect costs incurred for the Edwardsport Integrated Gasification Combined Cycle Generating Facility.

180. Duke Energy, Petition for Approval of Alternative Regulatory Plan for Carbon Storage, No. 43653, at 1 (IN URC 2009).

181. Commission's Investigation Related to Approval of Participation by Indiana End-Use Customers in Demand Response Programs, No. 43566, at 1-2 (IN URC 2009).

investigation was commenced to identify and appropriately address important factual, legal, and policy issues associated with the approval of end-use customer participation in RTO DRPs. Therefore, it is necessary and appropriate that the status quo be maintained. Indiana end-use customers are prohibited from participating in RTO DRPs pending further order.

In Cause No.43306,[182] the Commission authorized Indiana Michigan Power Company to increase its rates and charges to provide additional annual revenues of $41,630,000. The Commission approved the first rate increase for Indiana Michigan Power customers in 15 years. The utility had sought an increase of almost twenty-one in residential rates but the Commission allowed an increase averaging approximately 4.85%. The IURC declined the I&M's request for $2.537 million to be included in base rates for the proposed Demand Side Management/Energy Efficiency programs. Cause No. 43643[183] is the Commission's investigation into any and all matters related to the Commission's guidelines for integrated resource planning by an electric utility contained in 170 IAC 4-7 and submission of the 2009 Integrated Resource Plans. In Cause No. 42693[184] Phase II, the Commission initiated an investigation into the effectiveness of DSM programs in Indiana. In Cause No. 43501, Duke Energy reached a settlement on its smart-meter proposal with the Indiana Office of Utility Consumer Counselor, industrial consumers and the Citizens Action Coalition. Duke had made a request to upgrade its electric grid, including the use of "smart" electric meters. The settlement is pending before the Commission. On June 30, 2009, in Cause No. 43426,[185] (Phase II order), the Commission granted the petitioning utilities authority to recover through their retail electric rates the respective jurisdictional costs incurred by them in connection with their participation in the Midwest ISO ASM. In two orders issued June 30, 2009, in Cause No. 43665 and 43672,[186] for Nipsco and Sigeco, the Commission approved the settlement of the issues of recovery of jurisdictional costs incurred in connection with the MISO charge types for Day Ahead Revenue Sufficiency Guarantee Distribution charges and credits and Real Time Revenue Sufficiency Guarantee First Pass Distribution charges and credits. IURC held its annual summer energy forum in May, 2009. Where the state's largest electric providers explained their summer preparedness strategies to the Commission.

C. Iowa

On March 25, 2009, MidAmerican Energy Company (MidAmerican) filed with the Iowa Utilities Board (Board) an application for advanced ratemaking

182. Indiana Michigan Power Co., No. 43306, at 55 (IN URC 2009).

183. Integrated Resource Planning by an Electric Utility Contained in 170 IAC 4-7, No. 43643, at 1-2 (IN URC 2009).

184. Investigation into the Effectiveness of Demand Side Management Programs – Phase II, No. 42693, at 1-2 (IN URC 2009).

185. Petition for Approval of Changes in Operations and Recovery of Costs Required by MISO's Implementation of a Co-optimized, Competitive Market for Energy and Ancillary Services Markey, No. 43426, at 1 (June 30, 2009).

186. Joint Petition for Approval of Settlement Continuing an Established Mechanism for the Recovery of Jurisdictional Costs, No. 43672, at 1 (IN URC 2009).

principles in connection with its proposed 1001 MW Wind VII project to be built between 2009 and 2012.[187] On the same day, MidAmerican and the Office of Consumer Advocate (OCA) filed a joint motion to approve the settlement agreement previously entered into by the parties on March 9, 2009.[188] Pursuant to the settlement agreement, MidAmerican would be permitted to recover its actual capital costs up to caps set according to when the project is placed in service; in the event that MidAmerican's capital costs exceed the cap, the Company would be required to establish the prudence and reasonableness of the excess.[189] The settlement agreement also: 1) permits MidAmerican to earn a 12.2% return on common equity investment in the project when it is included in rate base; 2) permits MidAmerican to recover cancellation costs, amortized over a ten year period, in the event that the project, or any part of it, is cancelled for good cause; 3) sets the depreciation life of the project for ratemaking purposes at twenty years, to be revised if the manufacturer changes the twenty year design life of any of the turbines; 4) allocates the project to Iowa jurisdiction in the same manner as certain other generation facilities owned by MidAmerican; and, 5) specifies a contingent revenue sharing credit of $2,315 per MW of Wind VII capacity qualifying for bonus depreciation pursuant to TARP is to be used to offset the capital costs of MidAmerican's Walter Scott, Jr. Energy Center Unit 4 from 1009-2013; 6) specifies that so long as MidAmerican's parent's equity infusion in the project does not exceed fifty percent, no double leverage adjustment would be made to MidAmerican's revenue requirement; 7) specifies the accounting for renewable energy, CO2 and other environmental credits, production tax credit and wholesale sales revenue; and continues the revenue sharing previously in place with inclusion of revenue from Wind VII. MidAmerican and the OCA asked that the settlement agreement be approved on an expedited basis by May 29, 2009.[190]

On April 17, 2009, NextEra Energy Resources, L.L.C. (NextEra) intervened in the case, asking the Board to deny MidAmerican's application and to refuse to approve the settlement agreement. NextEra argues that MidAmerican's Wind VII proposal is unreasonable when compared to alternative sources of supply which can be provided by NextEra. On June 17, 2009, Iberdrola Renewables, Inc. (Iberdrola) intervened, arguing that its competitive interests may be affected by the case, given that NextEra intends to put alternative proposals to supply MidAmerican with wind generation before the Board and that NextEra had requested from MidAmerican any proposals received by the Company from other wind developers. Hearing in the matter is set to occur during the week of August 10, 2009. A decision is expected by year-end. In other matters, both Interstate Power Company and LS Power shelved their plans to build coal-fired generation. The Interstate Power decision came after the Board's decision on its Application for Ratemaking Principles in conjunction with its share of the proposed 649 MW Sutherland Generating Station Unit 4, which would have

187. Steven R. Weiss, Senior Vice President & General Counsel, *MidAmerican Application* (Mar. 24, 2009), *available at* https://efs.iowa.gov/efiling/groups/external/documents/docket/006911.pdf.

188. Order Granting Waiver of Settlement Agreement, No. WRU-2009-0012-0156, (IA DCUB 2009), *available at* https://efs.iowa.gov/efiling/groups/external documents/docket/006911.pdf.

189. *Id.*

190. *Id.*

allowed only a 10.1% return on Interstate's equity investment in that project.[191] In 2007, LS Power had announced plans to build a 750 MW plant near Waterloo, Iowa, but had not yet filed for a Certificate of Public Convenience and necessity with the Board when, in the midst of the economic downturn at the end of 2008, it announced that it would not pursue the project.[192]

D. Kansas

Senate Substitute for House Bill 2369 became effective on May 28 2009, and includes a renewable energy standard (RES), net metering provisions, and various other energy efficiency and energy-related provisions.[193] The Kansas RES mandates that electric utilities (excluding municipal utilities) obtain ten percent of their energy from renewable sources by 2011, fifteen percent by 2016, and twenty percent by 2020.[194] The Kansas Corporation Commission has begun the rulemaking process regarding various issues included in the new law, including: (1) the RES; (2) the administration of the renewable energy standards act; (3) the certification processes for the renewable energy standards act; (4) net metering; and (5) other issues. Senate Substitute for House Bill 2369 was the result of a settlement agreement between the Governor and Sunflower Electric Power Corporation regarding issuance of an air quality permit for construction of a new electricity generation facility at Holcomb.[195] Under the settlement agreement, Sunflower Electric agreed to reduce the size of its previous proposal from two 700-megawatt coal-fired plants to one 895-megawatt coal-burning plant in southwest Kansas, subject to various conditions. The settlement agreement will help facilitate the issuance of a Prevention of Significant Deterioration (PSD) construction permit for one additional 895 MW coal plant at Holcomb (i.e. Holcomb 2) contingent upon Sunflower complying with certain conditions.

As part of its five-year regulatory plan, Kansas City Power & Light Company (KCPL) filed a rate request with the Kansas Corporation Commission in September 2008.[196] The primary purpose of the filing was to recover costs for environmental upgrades at the Iatan 1 coal-fired power plant and common costs for the upgrades of that plant and construction of Iatan 2, a second coal-fired power plant under construction. Recently, the Commission approved the settlement agreement between KCP&L, the Staff of the Commission, the Citizens' Utility Ratepayer Board (CURB) that gave KPC&L a rate increase of $59 million.

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191. Power Engineering International, *Do Industry Fundamentals Suggest a Strong Recovery?*, http://pepei.pennnet.com/display_article/355441/6/ARTCL/none/none/1/Do-Industry-Fundamentals-Suggest-a-Strong-Recovery? (last visited Oct. 13, 2009).

192. Source Watch: *LS Power Elk Run Energy Station*, *available at* http;://www.sourcewatch.org/index.php?title=LS_Power_Elk_Run_Energy_Station.

193. Senate Substitute for H.B. 2369, 2009 Leg. (Ks 2009).

194. *Id.*

195. KDHE/Sunflower Electric Settlement Agreement, *available at,* www.holcombstation.coop/files/settlement_agreement.pdf.

196. Kansas City Power & Light Company Rate Change Application, No. 09-KCPE-246-RTS, at 1-3 (KCC 2008).

In May 2008, Westar Energy filed a rate request with the KCC seeking total rate increase of $177.6 million ($90.0 million in the Northern region, and $87.6 million in the South region).[197] The Commission approved the settlement agreement between Westar and the other parties to the rate case, which gave Westar a rate increase of $130 million. The settlement agreement also noted that costs related to construction and operation of wind generation owned by Westar and Phase II of the Emporia Energy Center (EEC) would be addressed in a future docket via Kansas's abbreviated ratemaking procedures. The settlement agreement also resulted in the issue of rate consolidation between Westar's north and south region being addressed in a subsequent docket. In February 2009, the Commission opened a new docket to address the issues of rate consolidation.[198] An order in this docket is due by October 26, 2009.

ITC Great Plains and Prairie Wind Transmission have been working with the Commission to determine which entity will be responsible to construct a 765 kV transmission line to connect Spearville and Wichita substations and to interconnect with a transmission line north out of Oklahoma.[199] ITC Great Plains' proposal was a V-shaped route that is approximately 180 miles in length, and Prairie Wind's proposal was a Y-shaped route in the same region that is estimated to be 230 miles in length.

If built, this transmission project will be a part of a network of Extra High Voltage (EHV) transmission lines commonly referred to as the EHV overlay that is being considered as part of the future transmission grid of the Southwest Power Pool (SPP). These issues are each being addressed in a consolidated docket, and the parties are operating under a procedural schedule in which the Commission is considering their respective applications in two separate phases.[200] In Phase I, the Commission will "evaluate Prairie Wind's application for a certificate and ITC's applications to amend its certificate, to determine whether these entities meet the qualifications to receive certificates of convenience that include the ability to construct their respective proposals."[201] In Phase II, "if both entities meet qualifications to receive certificates, the Commission would use its merger standards to determine which proposal is in the best interest of the public and will most benefit Kansas and the region."[202] In March 2009, ITC and Prairie Wind filed a settlement agreement resolving Phase I issues.[203] In "the settlement, ITC and Prairie Wind agreed that each entity is qualified to receive an amended certificate that would allow construction of the proposed transmission project."[204] Over the next several months, the Commission will examine the settlement agreement, proceed with its Phase II

197. Westar Rate Change Application, No. 08-WSEE-1041-RTS, at 1 (KCC 2008).

198. Kansas Corporation Comm'n Considers Issue of Rate Consolidation and Resulting Rate Design, No. 09-WSEE-641-GIE, at 1 (KCC 2009).

199. *Id.*

200. Consolidated Dockets Application to Transact Business of an Electric Public Utility, Nos. 08-PWTE-1022-COC, 08-ITCE-936-COC, 08-ITCE-937-COC, & 08-ITCE-938-COC, at 1 (KCC 2009).

201. Prairie Wind Transmission, No. 08-PWTE-1022-COC, at 3 (KCC 2009), *available at* http://www.kcc.state.ks.us/pi/press/advisory-09-01.pdf.

202. *Id.*

203. *Id.*

204. *Id.*

analysis, and according to the current procedural schedule, will issue an order by December 2009.

E. Michigan

On October 6, 2009, two new laws governing Michigan Public Service Commission (MPSC) regulation of public utilities became effective. 2008 PA 286[205] (Act 286) amended the statute that provides for the MPSC's general ratemaking authority in a number of respects. The most significant change contained in Act 286 is that it requires that an order in any rate increase application be issued within twelve months of the filing of the application or the application will be deemed to be granted. It also permits a utility to self-implement its requested rate relief within 180 days of the filing of the application unless the MPSC issues an order for good cause preventing or delaying the self-implementation. Act 286 expands MPSC jurisdiction to include approval of mergers of MPSC-regulated utilities with other entities.[206] The statute also grants the MPSC new authority to issue certificates of necessity for construction of an electric generation facility, for a significant investment in an existing electric generation facility, for purchase of an existing electric generation facility or for entering into a power purchase agreement for the purchase of electric capacity for a period of six years or longer.[207] The Act also requires that rates for service be set at the cost of service within five years. Currently, the commercial and industrial rates subsidize to some extent the residential rates.[208]

2008 PA 286 (Act 286) amended 2000 PA 141, (Act 141) the Customer Choice and Electric Reliability Act, and became effective on October 6, 2008.[209] Act 141 was passed in 2000 to, in part, ensure that all retail customers in Michigan have a choice of electric suppliers. Act 286 amended Act 141 to provide that "no more than 10% of an electric utility's average weather-adjusted retail sales for the preceding calendar year may take service from an alternative electric supplier at any time."[210] Act 286 further provides that existing customers who are taking electric service from an alternative electric supplier at a facility as of October 6, 2008, shall be given an allocated annual energy allotment for that service at that facility, and customers seeking to expand usage at a facility served by an alternative electric supplier will be given next priority with the remaining load, if any, allocated on a first-come first-served basis.[211] Act 286 also permits customers seeking to expand usage at a facility that has been continuously served through an alternative electric supplier since April 1, 2008, to continue to purchase electricity from an alternative electric supplier for both the existing and any expanded load at the facility, as well as any new

205. MICH. COMP. LAWS ANN. § 460.6c, *amended by* S. B. 216, 2007 Leg., 94th Sess. (Mich. 2007), MICH. COMP. LAWS ANN. § 460.10dd (2008) Mich. Pub. Act. 286 (*amending* 1939 Mich. Pub. Act 3), MICH. COMP. LAW § 460.1 *et seq*.

206. MICH. COMP. LAWS. § 460.6q (1939).

207. *Id.* at § 460.6s (1939).

208. *Id.* at § 460.11 (1939).

209. *Id.* at § 460.10 (1939) *et seq*.

210. *Id.* at § 460.10a(1)(a) (2008).

211. *Id.* at § 460.10a(1)(b) (2008).

facility, if the customer owns more than fifty percent of the new facility.[212] The Act also permits any customer owning an iron ore mining facility or iron ore processing facility located in the Upper Peninsula of Michigan to purchase electricity from an alternative electric supplier regardless of whether those sales exceed ten percent of the serving electric utility's average weather-adjusted retail sales.[213]

The second new act, 2008 PA 295 (Act 295), has numerous provisions requiring electric service providers to establish renewable energy programs and energy optimization programs.[214] All providers are covered by this new law including entities that previously were not regulated by the MPSC, such as municipal utilities. All of these providers were required to file plans and proposed surcharges designed to meet the renewable energy standards and energy optimization standards set forth in the Act and to propose surcharges to collect from ratepayers the necessary funds to carry out the plans. The Act set out a very short time frame to carry out this process by requiring that the MPSC issue an order within 90 days of the application being filed at the Commission. The orders relating to these plans filed by the State's utilities, including municipal utilities, cooperatives, and traditionally-regulated utilities, have been approved. Reconciliation of the amounts collected through the surcharges will be reconciled and the prudency of the programs carried out pursuant to these approved-plans will be assessed in reconciliation proceedings. Act 295 also provides for the creation of a Wind Energy Resource Zone Board. This Board will create a list of regions in the state with the highest level of wind energy harvest potential, among other things.[215] The MPSC also has authority pursuant to these sections of Act 295 to issue expedited siting certificates for a transmission line for electricity generated by wind energy conversion systems located in a Wind Energy Resource Zone. In addition, the Act requires the MPSC to establish a statewide net metering program.[216]

F. Minnesota

In 2005, Great River Energy and Xcel Energy along with several other Minnesota utilities began the CapX 2020 Transmission Expansion Initiative, a capacity extension plan meant to upgrade the electricity transmission infrastructure of the upper Midwest to meet projected demand for the year 2020. The first group of projects involved in the initiative includes three main transmission lines known as the Brookings, La Crosse, and Fargo Projects. As each project is considered to be a "large energy facility," certificates of need from the Minnesota Public Utilities Commission are required before the projects can go forward. The Commission issued an order in response to the requests for certificates of need on May 22, 2009. Certificates were granted for all of the projects, although the certificate for the Brookings Project was granted with conditions. The Commission specified that the certificate of need for the Brookings Project would require that the additional capacity created by that line

212. *Id.* at § 460.10a(1)(c) (2008).
213. *Id.* at § 460.10a(1)(d) (2008).
214. *Id.* at § 460.1001-460.1195 (2008).
215. *Id.* at § 460.1141-460.1161 (2008).
216. *Id.* at § 460.1171-460.1173 (2008).

must be available for transmitting electricity from renewable resources. Several petitions for reconsideration of the order are currently pending before the Commission. Organizations that are against the project, NoCapX 2020 and United Citizens Action Network, have alleged that the Environmental Report prepared for the project was insufficient. They also allege that the Commission should consider evidence showing a decrease in demand for electricity such that granting a certificate of need is now inappropriate. The Citizen's Energy Task Force requested reconsideration of several aspects of the order by questioning the grant of a certificate of need for the La Crosse Project and the necessity of the upsized double-circuit alternative for any of the approved CapX 2020 projects. The applicants for the certificates of need along with the Office of Energy Security have also submitted a petition for reconsideration to have the conditions on the Brookings line removed or modified. Great River Energy and Xcel Energy claim that the conditions on the Brookings line are unsupported by the record and would cause excessive risks and costs to the project.[217]

In 2005, a consortium of seven Minnesota power companies requested a certificate of need from the Minnesota Public Utilities Commission to build or upgrade "Big Stone II" transmission facilities between South Dakota and southwestern Minnesota. The two main lines for the project, the Morris and Granite Falls lines, were proposed to run from Big Stone City, South Dakota into Minnesota in order to transmit power from a planned coal-fueled power plant in Big Stone City known as Big Stone Unit II. Following years of hearings and attempted settlements, the Commission granted the requested certificate of need on March 17, 2009 provided numerous conditions are met by the consortium applicants in completing the project. The conditions include adhering to a 2007 settlement agreement between the consortium and the Minnesota Department of Commerce, which contained reporting obligations, a requirement to reduce carbon dioxide emissions in an amount equal to that emitted by Big Stone Unit II as a product of generating electricity for Minnesota consumers for the first four years of the plant's operation, installation of mercury emissions control technology, and an agreement to comply with Minnesota's Renewable Energy Standard requiring utilities to obtain twenty-five percent of retail customers' energy from renewable sources by the year 2025. The consortium applicants are also required by the Commission's order to ensure that the Big Stone facility will be carbon capture ready, examine the feasibility of using ultra-supercritical technology which would allow the plant to produce energy more efficiently, adhere to other reporting requirements, and decommission the Hoot Lake coal-fired generating station by 2018. Several parties petitioned for reconsideration

217. Order Granting Certificates of Need with Conditions, No. ET-2, E-002, *et al.* CN-06-1115 (MN PUC 2009), *available at* https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={54C51FAE-B774-4EED-A93C-CAF6ECC5EB52}&documentTitle=20095-37752-01; MN PUC, *CapX 2020 Project Description*, *available at* http://www.puc.state.mn.us/portal/groups/public/documents/pdf_files/011254.pdf; MN PUC, *Staff Briefing Papers* (July 14, 2009), *available at* https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={5F570BBB-CD86-43F3-AAD8-8660DA5FD99C}&documentTitle=20097-39474-01.

of the order, but all petitions were denied by the Commission as they did not indicate any new evidence to be considered or expose errors in the order.[218]

The Omnibus Energy Policy Bill (Energy Policy Act), Minnesota Law 2009, Chapter 110, was signed into law on May 19th, 2009. The Bill includes several notable provisions. Section 3 increases the amount of appraisal fees that may be awarded to a land owner in eminent domain cases from $500 to $1,500 and establishes a $3,000 cap for awards in cases involving a public service corporation's use of eminent domain for high-voltage transmission lines. Section 6 authorizes the Minnesota Public Utilities Commission to extend the suspension period in rate cases by an additional ninety days. Section 10 requires utilities to file a standardized contract with the Commission when purchasing electricity from projects of 5 MW or less. Section 14 authorizes the Commission to order any public utility to refund unlawfully collected revenue to customers. Section 28 directs the Department of Commerce to report to the legislature on the need for transmission infrastructure and the status of proposals for how to meet that need following consultation with the Commission. Section 33 calls for the Commission along with the Office of Energy Security to conduct a study of automatic cost-recovery mechanisms and alternative forms of utility rate regulation with the results of the study submitted to the legislature by June 30, 2010.[219] Minnesota has had a statutory moratorium prohibiting the construction of new nuclear power plants since 1994. The Minnesota Chamber of Commerce led an effort to lift the moratorium during the 2009 legislative session. The legislation passed the Senate but failed in the House by a close margin. It is expected this issue will be back in future sessions.

G. Missouri

In November 2008 voters in Missouri enacted Proposition C, a ballot initiative that repealed the state's existing voluntary renewable energy and energy efficiency objective and replaced it with an expanded, mandatory renewable electricity standard of fifteen percent by 2021, beginning at two percent in 2011 and gradually increasing every two or three years. The Missouri Public Service Commission (MoPSC) is currently promulgating a rule designed to carry out Proposition C.[220] In October 2008, the MoPSC promulgated various

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218. MN PUC, Big Stone II references include Staff Briefing Papers (Apr. 30, 2009), *available at* https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={CF21F692-C7E9-463F-9FF6-1F77D3E8C6AA}&documentTitle=20094-36642-01; MN PUC, Order Granting Certificate of Need with Conditions (March 17, 2009), *available at* https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={079156DF-2636-4B42-AD0D4B54E05E482D}&documentTitle=5822036; MN PUC, Order Denying Reconsideration, *available at* https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?Method=showPoup&documentId={CC6AE241-F8C2-4111-91BC-5837BC7FFB02}&documentTitle=20095-37245-01

219. MN PUC, *Summary of the Minnesota 2009 Energy Policy Act*, *available at* http://www.puc.state.mn.us/PUC/electricity/news-events/012110. Minnesota 2009 Energy Policy Act, Chap. 110, *available at* https://www.revisor.leg.state.mn.us/laws/?id=110&doctype=chapter&year=2009&type=0. Darlene Sliwa, S.F. No. 550 – Omnibus Energy Policy Conf. Comm. Report, (May 13, 2009), *available at* http://www.senate.leg.state.mn.us/departments/scr/billsumm/summary_display.php?ls=86&session=regular&body=Senate&billtype=S.F.&billnumber=550&ss_year=2009.

220. In the Matter of a Repository File Regarding the Renewable Energy Workshop, Docket No. EW-2009-0324 (MO PSC 2009).

rules regarding the Net Metering and Easy Connection Act that was part of Senate Bill 54. SB 54 was passed during the 2007 legislative session and became law in June 2007. Under the amended rules, Missouri investor-owned electric utilities are required to permit qualified interconnection to customers with systems up to 100 kW in capacity that generate electricity using certain renewable energy resources. Senate Bill 376, the Missouri Energy Efficiency Investment Act, which will become effective on August 28, 2009, will allow utilities to include the costs of qualifying energy efficiency programs in the package of costs that they may recover. To qualify, energy efficiency programs, which require Commission approval, must be cost-effective or in the public interest, result in energy savings and be beneficial to customers in the customer class in which it is proposed. The act allows the electric companies to implement certain programs that are paid for through alternate measures even if the programs do not meet the cost-effectiveness test.

In July 2008, the MoPSC approved the merger of Aquila with a subsidiary of Great Plains Energy, Incorporated, which operates Kansas City Power & Light, determining the merger is not detrimental to the public interest.[221] In determining that this merger was not detrimental to the public interest, the Commission examined the following factors: projected synergy savings, transaction and transition costs, post merger credit worthiness, service quality and customer service. As part of its decision, the commission determined that Great Plains Energy Incorporated would not be allowed to recover transaction costs from ratepayers. In September 2008, Kansas City Power & Light filed a rate request with the MPSC seeking a $101.5 million increase.[222] The primary purpose of the filing was to recover costs for environmental upgrades at the Iatan 1 coal-fired power plant and common costs for the upgrades of that plant and construction of Iatan 2, a second coal-fired power plant under construction. In June 2009, the MPSC approved a settlement agreement between the parties to the case that will result in an annual revenue increase of approximately $95 million. In September 2008, KCP&L Greater Missouri Operations ("GMO") filed a rate request with the MoPSC seeing a total rate increase of $83.1 million.[223] In June 2009, the MoPSC approved the settlement agreement in the GMO rate case, allowing GMO to receive an electric rate increase of approximately $48 million for its operations serving the territory it formerly served as Aquila Networks-MPS (MPS) and approximately $15 million for its operations serving the territory it formerly served as Aquila Networks-L&P (L&P).

In April 2008, AmerenUE filed a rate increase with the MoPSC seeking a $251 million rate increase.[224] In January 2009, the MoPSC issued an Order

221. Joint Application of Great Plains Energy Inc., Kansas City Power & Light Co., and Aquila, Inc., for Approval of the Merger of Aquila, Inc., with a Subsidiary of Great Plains Energy Inc., No. EM-2007-0374 (MO PSC 2008).

222. Kansas City Power & Light Co.'s Tariff Filing and Application for Approval to Make Certain Changes to Its Charges for Electric Service to Implement Its Regulatory Plan, Docket No. ER-2009-0089 (MO PSC 2009).

223. Kansas City Power & Light Greater Missouri Operations Co.'s Tariff filings Designed to Implement a General Rate Increase for Electric Service, Docket No. ER-2009-0090 (MO PSC 2009).

224. Revised Tariffs of Union Electric Company, d/b/a AmerenUE, Designed to increase Rates for Electric Service, Docket No. ER-2008-0318 (MO PSC 2008).

addressing AmerenUE's application, and granted it a $162.6 million increase. In its decision, the MoPSC authorized a return on equity of 10.76 percent and, granted a fuel adjustment clause with a ninety-five percent pass through of fuel expenses. In 2007, the MoPSC approved revenue decoupling mechanisms for Atmos Energy Corporation[225] and Missouri Gas Energy,[226] allowing the utilities to recover its non-gas costs through a straight fixed variable (SFV) rate design. Both of these cases are on appeal to the Missouri Court of Appeals. In each of these cases, the Missouri Office of the Public Counsel challenged the Commission's adoption of this rate design. As of the end of May 2009, these cases were still on appeal.[227] In July 2008, Laclede Gas Company filed tariff sheets with the MoPSC designed to permit Laclede to collect a portion of its bad debts through the Purchased Gas Adjustment (PGA) Actual Cost Accounting (ACA) process.[228] The Commission denied Laclede's request as unlawful.[229]

H. Nebraska

Nebraska is unique in that it is the only state in the country served entirely by publicly owned electric power entities, which include public power districts, cooperatives, and municipalities. In October 2008, the Nebraska Energy Office began to update its 1991 State Energy Plan. The initial phase of the process involved multiple comment sessions held across the state. The second phase of the update process began in December 2008 with the release of an interim State Energy Plan.[230] Comments regarding the draft plan were made through January 2009, and a finalized version is expected soon. According to the Nebraska Power Review Board, possible legislative recommendations and statutory changes may result after the Plan is finalized.

L.B. 436, creating Nebraska's net metering law, was passed in May 2009. This new law creates a statewide net metering policy, provides a credit for energy generated up to the amount used, and contains a prohibition against requiring additional liability insurance.[231] The Nebraska Legislature passed LB 561[232] in May 2009. This new law includes three important developments for wind and renewable energy in Nebraska. First, it allows the public power districts to waive their eminent domain authority for renewable generation

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225. In re Atmos Energy Corp.'s Tariff Revision Designed to Consolidate Rates and Implement a General Rate Increase for Natural Gas Service in the Mo. Service Area, Docket No. GR-2006-0387 (MO PSC 2006).

226. In re Mo. Gas Energy's Tariffs Increasing Rates for Gas Service Provided to Customers in the Companies' Mo. Service Area, Docket No. GR-2006-0422 (MO PSC 2007).

227. Atmos Energy Corporation et. al v. Missouri Public Service Commission, Missouri Court of Appeals, Western District, Case No. WD70219; Missouri Gas Energy, et al. v. Missouri Public Service Commission, Missouri Court of Appeals, Southern District, Case Nos. SD29297, 29320, 29278, and 29308.

228. Laclede Gas Company's Tariff Designed to Permit Early Implementation of Cold Weather Rule Provision, Docket No. GT-2009-0026 (MO PSC 2009).

229. *Id*.

230. Interim State Energy Plan, http://www.neo.ne.gov/comments2/PlanDraft2009.pdf (last visited Oct. 10, 2009).

231. More information on this law is available on the Nebraska Legislature's website, http://www.nebraskalegislature.gov/bills/view_bill.php?DocumentID=6796 (last visited Oct. 10, 2009).

232. More information on this law is available on the Nebraska Legislature's website, http://www.nebraskalegislature.gov/bills/view_bill.php?DocumentID=6941 (last visited Oct. 10, 2009).

facilities. Formerly, public power districts in Nebraska had the ability to condemn private generation facilities. Second, renewable generation facilities are exempted from meeting the "least cost" and "public convenience and necessity" criteria of the Nebraska Power Review Board. Third, there are various modifications Nebraska's Community Based Energy Development (CBED) systems, which are aimed at increasing wind development in Nebraska.

I. North Dakota

On August 27, 2008, the North Dakota Public Service Commission approved applications of Otter Tail Corporation and Montana-Dakota Utilities Co. for advance determination of the prudence of their participation and ownership interest in the Big Stone II Generating Plant, Case Nos. PU-06-481 and PU-06-482.[233] The proposed plant is a 630 MW[234] nominal capacity supercritical, pulverized-coal electric generating plant (Big Stone II) to be located adjacent to the existing plant in Big Stone City, South Dakota. The Commission found the proposed plant to be reasonable and prudent in light of the utilities' need for additional generating resources and the alternatives for meeting those needs. The Commission noted that under North Dakota Century Code Section 49-02-23[235] it may not utilize environmental externality values for the alleged or expected costs of potential carbon dioxide regulation when considering electric resources or setting electric rates. The statutory definition of externalities goes beyond the conventional understanding of externalities to include the expected costs of complying with carbon regulation not yet enacted. The Commission stated that while it is prohibited from considering quantitative environmental externality values, it can consider the possibility of carbon regulation in a qualitative manner. The Commission found that regulation of carbon dioxide would likely result in an increase in the cost of coal-fired electric energy and that it would also increase the costs of most kinds of generation. The Commission gives weight to the fact that economic risks associated with regulation of carbon dioxide are significant. Intervenors have appealed the decision based on the Commission's failure to consider the alleged costs associated with potential future regulation of carbon emissions. The appeal is pending in state district court.

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233. Pursuant to the Advance Determination of Prudence Statute, N.D. CENT. CODE § 49-05-16 (2008).

234. The size has since been reduced to 500 / 580 MW.

235. N.D. CENT. CODE § 49-02-23 governs the use, by the Commission or the electric utility, of environmental externality values when considering electric resources or electric rates. § 49-02-23 states:

> Consideration of environmental externality values prohibited.
>
> The Commission may not use, require the use of, or allow electric utilities to use environmental externality values in the planning, selection, or acquisition of electric resources or the setting of rates for providing electric service. Environmental externality values are numerical costs or quantified values that are assigned to represent either:
>
>> 1. Environmental costs that are not internalized in the cost of production or the market price of electricity from a particular electric resource; or
>>
>> 2. The alleged costs of complying with future environmental laws or regulations that have not yet been enacted.

J. Ohio

On May 1, 2008, Governor Strickland signed Am. Sub. S.B. No. 221, which significantly alters the framework of electric utility regulation in Ohio. In 1999, Ohio had largely deregulated electric generation. Electric utilities went through five-year transition plans. When competition failed to develop during that period, the transition plans were replaced by "rate stabilization plans." Most of the utilities' plans were set to expire at the end of 2008. Under the new legislation, each electric distribution utility must provide a standard service offer (SSO) to all customers who do not choose another supplier. An electric utility may propose an SSO under either or both of two methods. Under R.C. 4928.142 (the market-based option), a utility meeting certain criteria may propose an auction to be conducted under PUCO rules. Under R.C. 4928.143 (the cost-based option), a utility may propose an electric security plan (ESP) that provides for recovery of prudently-incurred fuel and purchased power costs. A proposed plan under either option must be approved by the Commission. The legislation also contains benchmarks for alternative energy resources as a component of an SSO. The portion obtained from alternative energy resources is to reach twenty-five percent by 2025.

K. Oklahoma

In July 2008, Public Service Company of Oklahoma (PSO) filed a rate request with the Oklahoma Corporation Commission (OCC) seeking a $132.6 million rate increase, which was later revised by PSO to $126.6 million.[236] In January 2009, the Commission ultimately approved a rate increase of $81.4 million, which included a base rate increase of $59.2 million and an additional $22 million increase for costs to be recovered through riders, including purchased power, investment in distribution infrastructure and generation maintenance expenses. The Commission also granted PSO a 10.5% ROE. In February 2009, Oklahoma Gas and Electric (OG&E) filed a rate request with the OCC seeking a $110 million rate increase.[237] In support of its request, OG&E said it has spent about $1.6 billion in new power plants and improvements to power lines, substations and other equipment since the commission authorized a $42 million rate boost in 2006. But more than $900 million of that investment is not covered in current electric rates, which are based on 2004 costs. The Commissioners are expected to make a decision in the OG&E case later this summer.

L. South Dakota

The South Dakota Public Utilities Commission considered two notable energy dockets recently. The PUC granted TransCanada Keystone Pipeline, L.P. a permit to construct the Keystone Pipeline through South Dakota. Keystone will be one of South Dakota's largest construction projects, traveling over 200 miles through the state on its way from Hardisty, AB to Cushing, OK. The

236. Final Order Revenue Distribution, No. 2008001444 (OCC PUD 2008).

237. In re Application of Oklahoma Gas & Electric Co. for an Order of the Commission Authorizing Applicant to Modify Its Rates, Charges, and Tariffs for Retail Electric Service, No. 200800398 (OCC PUD 2008).

crude oil facility is currently under construction under the permit.[238]South Dakota's comprehensive Energy and Transmission Facilities Siting Act, SDCL 49-41B, vesting jurisdiction in the PUC to grant a permit, with conditions, was developed over time and had not been applied to a hydrocarbon pipeline in recent years. The state of the art Keystone Pipeline presented some novel questions in the areas of notice, and due process, as well as the more traditional substantive questions. Some legislation was offered and passed as a result. TransCanada Keystone has a second pipeline project docketed before the Commission at this time. The PUC also granted a permit under the same chapter of the code to the Buffalo Ridge II wind farm. Iberdrola Renewables proposed BRII for Brookings and Deuel Counties along the Coteau de Prairies region of eastern South Dakota. A 306 megawatt project, it is the first large scale wind farm permitted by the PUC. The issues presented were novel in two respects. It is the first "permit the box" project of any sort, invoking a determination by the PUC regarding a statute in the Act which withholds authority to site or route facilities from the Commission. Previously the Commission had held that authority to require the applicant to determine exact locations for facilities prior to the granting of a permit. In the instant case however, the Commission determined that any location within the project boundaries which met the applicable criteria was a potential location for a tower under the permit. The Commission also determined that locations which met the local zoning ordinances and the conditions of the permit would not be 'second-guessed' as to alleged effects upon neighboring landowners. Two neighboring landowners requested additional setbacks for alleged reasons such as electrical interference, noise and shadow flicker. The Commissioners took evidence and determined that they had no authority to substitute their judgment for that of the County regarding setbacks, and any effects of the wind farm on neighboring landowners would have to be judged after construction for compliance with the permit conditions.

M. Wisconsin

In November 2008, the Public Service Commission of Wisconsin denied Wisconsin Power and Light's plan to build a new 300 megawatt coal-fired electric generation facility. The PSC decided that the $1.26 billion project was too costly when weighing it against other alternatives such as natural gas generation and the possibility of purchasing power from existing sources. Concerns over construction costs and uncertainty over the costs of complying with future possible carbon dioxide regulations were all contributing factors to the denial, not sufficient to offset the project's risks Wisconsin Power and Light's effort to burn up to twenty percent renewable biomass in the facility .

The Wisconsin PSC has approved two significant transmission projects. The Paddock-Rockdale line, a thirty-five mile long 345 kV facility, was approved on June 13, 2008.[239] The PSC decision relied on an economic rationale, rather than need to address a specific reliability issue, pointing out that the project would reduce the cost of purchased power for customers by reducing

238. The online docket can be found at: http://www.puc.sd.gov/Dockets/HydrocarbonPipeline/2007/hp07-001.aspx (last visited Oct. 12, 2009).

239. Application of American Transmission Company, Docket 137-CE-149 (WI PSC 2008).

the locational marginal prices in Wisconsin closer to the average costs in the Midwest ISO markets. The project's costs and benefits were tested under seven future scenarios; the PSC found net economic savings under most futures and metrics. A connecting facility, located in the Madison metropolitan area, was subsequently approved using a conventional reliability analysis, to improve the transmission service for Dane County to avoid serious reliability problems in the near future.[240] Investment in the two projects will exceed $300 million.

V. WESTERN & SOUTHWESTERN REGION

Five of the Western & Southwestern Region's states have to a degree permitted retail market competition in electricity, but three have substantially withdrawn or not actively implemented that permission. As described below, retail competition has achieved strong results in Texas. Proceedings to examine the status or possible expansion of retail competition in state markets in the region were active in at least two states also as described below. As in other regions of the country, development of needed new generation and transmission, including particularly renewable generation and demand response programs, is being encouraged with both legislative and regulatory actions. The development of both renewable generation, and particularly the identification and development of Renewable Energy Zones and needed transmission to exploit them, is being encouraged by the Western Governors Association.[241]

A. Arizona

The Arizona Corporation Commission (ACC) issued interim or final decisions in four general rate cases during the reporting period. Among them was the first general rate case for Tucson Electric Power (TEP) since the rate freeze enacted in 1999. The ACC approved a settlement between TEP and other parties which provided that (1) TEP's generation rates would determined on a cost-of-service basis and not at market rates, (2) TEP's service territory would remain open to retail electric competition pending resolution of competition-related issues in another docket, (3) adjuster mechanisms for fuel and purchased power, renewable energy and demand side management programs would be established, and (4) TEP's rates would be frozen through December 31, 2012.[242] TEP's affiliate, UNS Electric received a rate case disallowance from the ACC for recovery of Construction Work in Progress or, alternatively, a request to add post-test year plant to its rate base. UNS received an additional disallowance of $10,906 in expenses for contract work performed by an affiliate. The decision provided for a fair value rate base of $167,551,067, and a 9.02% weighted average cost of capital consisting of 10.0% return on equity, 8.22% return on long-term debt and 6.36% return on short-term debt.[243] While its general rate case was pending, the ACC approved a $65.2 million interim rate increase for Arizona Public Service Company (APS) after determining that it had jurisdiction

240. Application of American Transmission Company, Docket 137-CE-147 (WI PSC 2009).

241. These efforts are fully described at http://www.westgov.org (last visited Oct. 10, 2009).

242. In re Application of Tucson Electric Power Co. for the Establishment of Just and Reasonable Rates, Docket Nos. E-01933A-07-0402 & E-01933A-05-0650 (ACC 2008).

243. In re Application of UNS Electric, Inc. for the Establishment of Just and Reasonable Rates, Docket No. E-04204A-06-0783 (ACC 2008).

to grant such interim relief because APS was facing an emergency.[244] Southwest Gas Corporation was awarded a 7.96% cost of long term debt, 8.20% cost of preferred stock, 10.0% cost of equity, and 1.0% fair value rate base increment for a 7.02% weighted average cost of capital. However, the ACC rejected Southwest Gas' proposed revenue decoupling mechanisms and volumetric rate design pending resolution of those issues in a separate docket. The ACC disallowed recovery of forty percent of Southwest's dues payments to the American Gas Association, fifty percent of its management incentive payments and 100% of Supplemental Executive Retirement Plan expenses.[245]

The advancement of retail competition in Arizona was put to a halt when the ACC suspended consideration of the application of Sempra Energy Solutions LLC for a Certificate of Convenience & Necessity (CC&N) to operate as an electric service provider in Arizona.[246] Sempra's application was the first to be filed after the prior CC&Ns were invalidated by the Court of Appeals of Arizona.[247] The ACC determined that, before it could consider the application, it first needed to determine "whether it is in the public interest at this time to grant CC&Ns authorizing the provision of competitive retail electric services to end users in Arizona"[248] and transferred the issues to its generic docket on electric restructuring. A challenge to the ACC's jurisdiction to impose a mandatory renewable energy standard on Arizona utilities was filed by the Goldwater Institute. After the Institute's Petition for Special Action was rejected by both the Supreme Court of Arizona[249] and the Court of Appeals of Arizona,[250] the case was brought as a complaint in the Superior Court for Maricopa County.[251] Oral argument on cross motions for summary judgment was heard on May 18, 2009. In other actions, the ACC adopted rules for net metering,[252] eliminated free allowances for line extensions for APS customers[253] and approved a notice of intent by Pinnacle West Capital Corporation to issue $400 million in APS equity.[254]

B. California

The California Public Utilities Commission (Commission) determined that it does not have discretionary authority under California statutes to lift the

244. In re Application of Arizona Public Service Co. for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, Docket No. E-01345A-08-0172 (ACC 2008).

245. In re Application of Southwest Gas Corp. for the Establishment of Just and Reasonable Rates, Docket No. G-01551A-07-0504 (ACC 2008).

246. In re Application of Sempra Energy Solutions, L.L.C. for a Certificate of Convenience and Necessity for Competitive Retail Electric Service, Docket No. E-03964A-06-0168 (ACC 2008).

247. Phelps Dodge Corp. v. Ariz. Elec. Power Coop., Inc., 207 Ariz. 95 (2004).

248. In re Application of Sempra Energy Solutions, L.L.C. for a Certificate of Convenience and Necessity for Competitive Retail Electric Service, Docket No. E-03964A-06-0168 (ACC 2008).

249. Miller v. ACC, Docket No. CV-08-0196-SA (2008).

250. Miller v. ACC, Docket No. SA-08-0261(2008).

251. Miller v. ACC, Docket No. 2008-029293 (2009).

252. In re Proposed Rulemaking Regarding Net Metering, Docket No. RE-00000A-070608 (ACC 2008).

253. In re Application of Arizona Public Service Co.-Revised Line Extension Tariff Schedule 3, Docket Nos. E-01345A-05-0816, E-01345A-05-0826, E-01345A-05-0827 (ACC 2008).

254. In re Pinnacle West Capital Corp. to Provide Notification of Its Intent to Increase Its Equity Interest in Arizona Public Service Co. Under A.A.C. R14-2-803, Docket No. E-01345A-08-0228 (ACC 2008).

suspension of "direct access" for retail electric service.[255] The Commission interpreted the language of AB1X (codified in California Water Code § 80110) and concluded that the direct access suspension, which was instituted to resolve the consequences of the 2000-2001 electricity crisis, must continue until the California Department of Water Resources (DWR) no longer supplies power. Because DWR currently holds title to the power under DWR contracts and still legally sells power to retail customers, AB1X would not permit the Commission to lift the suspension on direct access. The Commission nevertheless decided to move onto Phase II of the proceeding exploring the possibility of instituting direct access, which includes considering alternative approaches to terminating DWR's ownership interests under existing contracts.

The Commission adopted a settlement proposed by Southern California Edison Company (SCE) and the Division of Ratepayer Advocates (DRA) to allow $1.63 billion in ratepayer funding for SCE's proposed Advanced Metering Infrastructure (AMI) Project.[256] The Commission concluded that the settlement is consistent with the public interest as there are between $9 million and $304 million in net benefits in the Settlement Agreement. The purpose of the AMI Project is to help transform California's utility distribution network into a smarter energy grid.[257] AMI-enabled electric meters (which will be known as Edison SmartConnect) will be able to measure energy usage on a time-differentiated basis, which "will improve customer service by providing customer premise endpoint information, assisting with electric systems outage detection, and providing real near-term usage information to customers." The meters will increase demand response (DR), allowing dynamic pricing that can reduce electricity demand during peak periods.[258]

The Commission authorized the Pacific Gas and Electric Company's (PG&E) SmartMeter Program Upgrade proposal for a cost of approximately $467 million, and the corresponding increase in revenue requirements to cover this cost.[259] This upgrade includes (1) an integrated load-limiting connect/disconnect switch, (2) a home area network (HAN) gateway device, (3) and an advanced solid state meter.[260] The Commission made the following orders: (1) the most cost effective way to provide HAN access is through a long-term meter development plan;[261] (2) PG&E shall develop a two-tier peak time rebate incentive; (3) PG&E shall provide quarterly progress reports on the implementation of the SmartMeter;[262] (4) PG&E shall annually report the energy savings and other financial benefits of all enabled programs;[263] (5) PG&E shall

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255. Rulemaking Regarding Whether, Or Subject to What Conditions, the Suspensions of Direct Access May Be Lifted Consistent with Assembly Bill 1X and Decision 01-09-060, D08-02-033, 263 P.U.R.4th 566 (CA PUC 2008).

256. Southern California Edison Co.'s Application for Approval of Advanced Metering Infrastructure Deployment Activities and Cost Recovery Mechanism, D08-09-039 (CA PUC 2008).

257. *Id.*

258. *Id.* at 2-3.

259. Application of Pacific Gas and Electric Company for Authority to Increase Revenue Requirements to Recover the Costs to Upgrade its SmartMeter TM Program, D09-03-026 (CA PUC 2009).

260. *Id.*

261. *Id.* at 176.

262. *Id.* at 189.

263. *Id.* at 196.

ensure that there is no double recovery of authorized SmartMeter Upgrade costs, nor double counting of energy conservation benefits; and (6) PG&E shall pursue automated meter reading for water meters by working with the water utilities in its service territory.[264]

The Commission found that it is in the public interest to establish the California Institute for Climate Solutions (CICS) to combat climate change by reducing greenhouse gas (GHG) emissions.[265] CICS will accelerate research and development (R&D) of technologies that will potentially reduce GHG emissions and assist California in adapting to climate change. Funding for CICS will come from a new surcharge on customer bills, raising $60 million per year for 10 years. The Strategic Research Committee (SRC) of CICS will develop a Strategic Plan that will identify the areas of R&D most likely to achieve the greatest GHG reductions at the lowest cost. The SRC will also develop a ratepayer benefits index, which will rank proposals by ratepayer benefit.[266] The Commission also established several means of ensuring the transparency and accountability of CICS, including representation of the Division of Ratepayer Advocates on the Governing Board of CICS. Finally, the Executive Director of CICS shall prepare comprehensive performance reviews, an annual external financial audit, a yearly budget, and an annual report.[267]

The Commission approved SCE's agreement with Alta Windpower Development, L.L.C. for the Alta Project, which is the largest wind energy contract in the United States.[268] The Alta Project will generate a minimum of 1,500 MW from facilities in the Tehachapi Wind Resource Area in Kern County to satisfy SCE's obligations under the California Renewable Portfolio Standard (RPS). The Commission ruled that the Alta Project meets RPS solicitation protocol as well as the requirements of the bid evaluation process dictated by the "Least Cost Best Fit" decision.[269] The SCE-Alta agreement has two aspects: the Master Agreement provides that each wind generating facility which Alta proposes to finance, build, own and operate will then be presented for approval to SCE; subsequently, Alta will draft a separate power purchase agreement (PPA) for each facility. Further, the SCE-Alta agreement outlines pricing structures for generating facilities to implement PPAs between 2007 and 2020, providing the Commission with a minimum and maximum target price for the contracting structures. The Commission found that the potential prices were per se reasonable as an RPS contract because the target price maximums were all at or below the energy price maximum for the applicable calendar year, and therefore all at or below the Market Price Referent (MPR).

The Commission's decision established a $108 million Multifamily Affordable Solar Housing (MASH) program, as a division of the California

264. *Id.* at 3, 197.

265. Order Instituting Rulemaking to Establish the California Institute for Climate Solutions, D08-04-039, 265 P.U.R.4th 1 (CA PUC 2008).

266. *Id.* at 59.

267. *Id.* at 74-75.

268. In re Application of Southern California Edison Co. for Approval of Renewables Portfolio Standard Power Purchase and Wind Project Development Agreement with Alta Windpower Development, L.L.C., D08-05-017 (CA PUC 2008).

269. *Id.* at 11-13.

Solar Initiative (CSI),[270] to encourage use of solar energy, particularly among low-income households, via solar incentives to qualifying affordable housing developments.[271] MASH will be administered in the service territories of PG&E, SCE and San Diego Gas & Electric Company (SDG&E). CSI Program Administrators will administer two tracks of incentives to encourage the use of solar energy. Track 1 offers fixed, up-front rebates for customers.[272] Track 2 allows applicants to receive grants above the Track 1 incentive level if financial need is established and the system will provide a "direct tenant benefit." The Commission also implemented several mechanisms to troubleshoot potential administrative problems and to avoid gaming concerns.[273] The Commission set the following targets for MASH: (1) implementation within four months of the Commission's order; (2) 50 completed affordable housing solar installations from MASH funds by 2012; and (3) outreach to affordable housing communities by 2010.[274]

The Commission considered the proposed Emerging Renewable Resource Program (ERRP) to increase renewable generation and decrease greenhouse gases (GHG).[275] Of the three projects proposed within ERRP, the Commission only approved PG&E's $4.8 million in initial assessment expenditures for the first stage of the WaveConnect project. The first stage of WaveConnect will investigate the feasibility of a facility to convert wave energy into electricity via wave energy conversion (WEC) devices in the open ocean waters near PG&E's service territory.[276] The Commission supported the first stage of the WaveConnect project for several reasons: (1) the licensing timeline associated with the March 2008 preliminary FERC permit for WaveConnect would likely be disrupted if ERRP funding was not awarded, (2) twenty-three percent of California's current energy consumption could potentially be produced through wave energy, (3) SB 1078, SB 107 and AB 32 encourage taking "reasonable and cost effective means to increase renewable development and mitigate GHG emissions" and (4) California's unique opportunity to harvest the "enormous supply" of renewable energy in the oceans, where "no meaningful ocean energy project is currently in production along California's coast."

The Commission granted a motion to dismiss PG&E's application seeking expedited approval and issuance of a Certificate of Public Convenience and Necessity (CPCN) for the Tesla Generating Station, a 560-megawatt natural gas-fired, combined-cycle generating facility that would have been located in eastern Alameda County.[277] The Western Power Trading Forum / the Alliance for Retail

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270. Order Instituting Rulemaking Regarding Policies, Procedures and Rules for the California Solar Initiative, the Self-Generation Incentive Program and Other Distributed Generation Issues, D08-10-036 (CA PUC 2008).

271. *Id.* at 2.

272. *Id.* at 8-9.

273. *Id.* at 17-43, 14, 19, 28-29, 33.

274. *Id.* at 40.

275. Application of Pacific Gas and Electric Co. and San Diego Gas and Electric Co. for Approval of Their Separate Emerging Renewable Resource Programs, D09-01-036 (CA PUC 2009).

276. *Id.* at 10-14.

277. Application of Pacific Gas and Electric Co. for Expedited Approval of the Tesla Generating Station and Issuance of a Certificate of Public Convenience and Necessity and Request for Interim Order Authorizing Early Project Commitment to Stabilize Costs, D08-11-004 (CA PUC 2008).

Energy Markets and the Independent Energy Producers Association, moved to dismiss PG&E's application for failing to comply with the Commission's procurement policy for approval of a utility-owned generating resource. The Commission only allows utilities to bypass a competitive process for resource procurement if it demonstrates that there are "truly extraordinary circumstances," which include situations when the procurement "provides a unique opportunity or is needed to meet specific, unique reliability needs." Despite an ALJ ruling to the contrary, the Commission found that PG&E did not meet this threshold requirement and specifically did not show how the Tesla Generating Station would meet unique needs that were unavailable through a competitive process.[278]

The Commission denied without prejudice SDG&E's petition to begin a rulemaking proceeding regarding regulations of overhead electric lines to reduce wildfire hazards.[279] Though the Commission recognized the need to address utilities' role in the 2007 wildfires in Southern California, such rulemaking would be premature because the investigations of the Commission's Consumer Protection and Safety Division (CPSD) and the California Department of Forestry and Fire (Cal Fire) were not complete. The decision outlined topics for CPSD's future investigation, including: (1) whether overhead electric lines contributed to the ignition of the 2007 wildfires; (2) whether overhead lines were properly designed, constructed, and maintained; (3) whether trees were properly trimmed; and (4) whether any wildfires were an unavoidable result of extreme weather. SDG&E's proposal to consider better means for coordinating disaster management among governmental bodies as well as development and funding of a statewide disaster management plan were found not to be within the current jurisdiction of the Commission.

Almost four years after a request from SDG&E, the Commission granted a CPCN for the Sunrise Powerlink Transmission Project (Sunrise). Sunrise consists of a 150-mile transmission line between California's Imperial and San Diego Counties with capacities of 230 kV or 500 kV.[280] The project also includes replacement of transmission cables for other lines, a new substation, and modification of several other substations. Upon examining the environmental effects, the Commission decided to not locate part of the line in the Anza-Borrego Desert State Park. The Commission anticipates that Sunrise will meet demand growth and will facilitate renewable energy development (with the possibility of the development of at least 1900 MW of renewable energy), greenhouse gas reduction objectives, and over $15 million in annual net benefits to ratepayers.[281] Concerned about the risk of wildfires and consequent power outages, the Commission also required SDG&E to implement fire safety measures.[282]

The Commission, supporting an Alternate Decision of President Peevey, authorized a $4.829 billion base revenue requirement for test year 2009 for

278. *Id.* at 24.

279. Petition of San Diego Gas & Electric Co. to Adopt, Amend, or Repeal a Regulation Pursuant to Public Utilities Code Section 1708.5, D08-05-030 (CA PUC 2008).

280. In re Application of San Diego Gas & Electric Co. for a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project, D08-12-058 (CA PUC 2008).

281. *Id.* at 2-3.

282. *Id.* at 217-18.

SCE.[283] The Commission's authorization marks a 28.8 percent increase over the 2006 authorized revenue requirement of $3.749 billion. As a result of the decision, SCE's projected total company revenue requirement for 2008 is approximately $12.5 billion. SCE requested funds for activities previously authorized by the Commission. However, because of unforeseen customer and load growth in previous years, SCE had to divert funds originally intended for capital replacements and apply them to address immediate customer needs. The Commission also noted that reductions to SCE's revenue requirement reflected concerns over the recent economic downturn. Notably, SCE's requests included a $2.094 million increase in funding to support efforts to develop and employ "smart" technologies on the electric grid,[284] and a $10.624 million increase for a Transmission Line Clearance Study.

The Commission concluded that, for a period of seven years, SCE manipulated and submitted false customer satisfaction data in order to gain Performance Based Ratemaking (PBR) customer satisfaction rewards.[285] The Commission ordered SCE to refund its ratepayers all $28 million of PBR customer satisfaction rewards and to forgo an additional $20 million in requested rewards. Additionally, due to SCE's submission of false and misleading health and safety data, the Commission ordered SCE to refund ratepayers $20 million in PBR health and safety rewards and forgo $15 million in requested rewards. The Commission also ordered SCE to refund the portion of its 2003 to 2005 revenue requirement related to the utility's Results Sharing program affected by the fraudulent data, totaling over $32 million. Finally, the Commission ordered SCE to pay a $30 million fine for violations of the Code. The Commission adopted a set of protocols for estimating the impact of demand response (DR) activities on the electric load for improved assessment of IOU proposals and activities.[286] Such protocols would improve consistency and accuracy. Although the Commission emphasized that future analysis of DR programs should be flexible, the Commission adopted twenty-six protocols addressing ex post evaluations, ex ante estimations and forecasts of impact of DR resources, sampling methods, and reporting requirements.[287] The Commission ordered SCE, SDG&E, and PG&E to file initial evaluation plans on all DR activities for 2008. The three IOUs, as of May 1, 2009, filed their initial evaluation plans. The Commission also ordered the IOUs to perform annual studies of their DR activities using the adopted protocols on April 1 of each year.

The Commission approved the transfer of a 100 percent controlling interest of Lodi Gas Storage, L.L.C. (LGS) from Lodi Holdings, L.L.C. (Lodi Holdings)

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283. Application of Southern California Edison Co. for Authority to, Among Other Things, Increase Its Authorized Revenues for Electric Services in 2009 and to Reflect that Increase in Rates and Related Matters, D09-03-025 (CA PUC 2009).

284. *Id.* at 333-4.

285. Investigation on the Commission's Own Motion into the Practices of the Southern California Edison Co. to Determine the Violations of the Laws, Rules, and Regulations Governing Performances Based Ratemaking, D08-09-038 (CA PUC 2008).

286. Order Instituting Rulemaking Regarding Policies and Protocols for Demand Response Load Impact Estimates, Cost-Effectiveness Methodologies, Megawatt Goals and Alignment with California Independent System Operator Market Design Protocols, D08-04-050 (CA PUC 2008).

287. *Id.* at 8.

to Buckeye Gas Storage, L.L.C. (Buckeye) for $440 million.[288] The Commission had previously granted LGS a CPCN to build and operate the Lodi Gas Storage Facility and the Kirby Hills Facility. LGS also sought to amend the CPCN to allow for expansion of the Kirby Hills Facility The Decision set the following five settlement conditions: [289] (1) the entities that take control of LGS must provide sufficient capital in order to maintain a safe and reliable public utility service; (2) LGS must make its books and corporate records available to the Commission; (3) LGS must report any acquisition by an LGS affiliate of any natural gas or electricity storage or distributor; (4) LGS may not share any Sensitive Market Information with competitor Wild Goose; and (5) in order to avoid commonality of interest, no director or employee of Lodi Gas may have a similar relationship at Wild Goose. The Commission also determined that an environmental review was not required due to an exemption from the California Environmental Quality Act (CEQA).

C. Colorado

Over the past 18 months, Colorado has expended considerable effort developing renewable energy sources both to achieve the mandates of a Renewable Energy Portfolio Standard and a state imposed greenhouse gas (GHG) reduction program. Colorado utilities are required to achieve twenty percent electricity sourced from renewable energy by 2020, and to reduce GHG emissions by twenty percent from 2005 levels by 2020.[290] Both Public Service Company of Colorado (PSC, an Excel Corporation subsidiary) and Black Hills, major electricity suppliers and generators in the state, have submitted and received Colorado Public Utility Commission (CPUC) Orders adjudicating Integrated Resource Plans for the addition of future generation.[291] PSC has agreed, as part of its approved plan, to retire five older and smaller coal fired generation units, to pursue DSM and energy efficiency programs to save up to 1,744 GWH of energy and 421 MW of demand and to add up to 1450 MW of renewable generation. It has also sought CPUC approval to waive Colorado requirements that it seek such new capacity through an RFP comparing the benefits of utility-build against IPP project proposals, but that waiver request has been denied. Black Hills requested waiver of the requirement to permit it to build up to five gas-fired units (approximately 350 MW), but was granted the

288. Joint Application of Lodi Gas Storage, L.L.C., Western Hub Properties, L.L.C., *et al*, D08-04-033 (CA PUC 2008).

289. *Id*. at 29-32.

290. In re Public Service Co. of Colorado for Approval of Its 2007 Colorado Resource Plan, Docket No. 07A-447E, at 1-9, Dec. C08-0929 (CO PSC 2008).

291. In re Public Service Co. of Colorado for Approval of its 2007 Colorado Resource Plan, Docket No. 07A-447E, Dec. C08-0929 (CO PUC 2008); Press Release, CPUC, PUC Strikes Balance in Ruling on Black Hills Resource Plan, *available at* http://www.dora.state.co.us/puc/publications/NewsReleases/02-11-09NR_PUCbalanceBlackHills-ERP.htm. CPUC also pursued an investigation to consider amendments to its Electric Resource Planning Rules in 2008 to more effectively plan for electricity needs in electric cooperative service territories. In re Amendments to the Electric Resource Planning Rules, Docket No. 09I-041E, Dec. C09-0092 (CO PUC 2009). Both utilities have issued RFPs to initiate acquisition of the future supply authorized in the CPUC Orders. *See* PSCO details response to All-Source RFP, MEGAWATT DAILY, vol. 14, no. 102, at 8 (May 29, 2009) & Black Hills Unit seeks Colorado Power Supplies,, MEGAWATT DAILY vol. 14, no. 59 (March 27, 2009).

requested waiver as to only two and must obtain IPP bids for the remaining three. PSC and Black Hills are also developing joint transmission proposals for consideration by the CPUC to permit expanded development of renewables under Colorado's Renewable Energy Zone Program, and have received approval of both demand response and renewable energy purchase programs available to customers.[292] Each has also filed several recent rate requests which have or are being adjudicated by the CPUC.[293]

D. Nevada

Nevada has recently adopted and the Nevada Public Service Commission (NPSC) has initiated rulemaking dockets to implement the establishment of renewable energy zones in the State.[294] This same legislation has increased Nevada's Renewable Performance Standard to twenty-five percent by 2025 and provides incentives for transmission development to enable project development in the identified renewable energy zones. A Task Force established by the Governor has already identified several such zones and transmission corridors whose development is needed to reach these zones. Additional legislation creates the Renewable Energy and Energy Efficiency Authority to work with developers to implement renewable energy projects and a fund to make loans for such projects.[295] The NPSC has also approved NV Energy's proposed acquisition of an IPP natural gas fired generation plant, the construction of a second plant to meet expanding service requirements and the acquisition from IPPs of renewable electricity supply.[296] Also, pending before it are applications for certification of several coal-fired generation facilities and numerous renewable plants (i.e. geothermal, wind & solar). Proposals to construct a major transmission line connecting Nevada's southern and northern electric grids, as well as several lesser lines, are also under-development, and a number of rate cases are pending or have been adjudicated before the Commission.[297]

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292. *See* Ethan Howard, *Excel to Tap 3,600 MW of Renewable Resources in Colorado by Adding Transmission*, ELECTRIC UTILITY WEEK, Dec. 22, 2008, at 25; Housley Carr, *Xcel Energy Proposes Innovative Clean Technology Program to Support State's Clean Energy Leadership*, RESOURCE WEEK, Feb. 1, 2009, at 31. In conjunction with several nearby States, the Western Governors Association and the U.S. DOE, issued a Phase I Report on transmission expansion for renewable supply development and a series of papers which examine evaluation factors and siting considerations for multi-state transmission lines. *See, e.g.*, WESTERN GOVERNORS' ASSN. & DOE, WESTERN RENEWABLE ENERGY ZONES – PHASE 1 REPORT (2009), *available at* http:www.westgov.org/wga/initiatives/ wrez/; Law Conference 2009 - Multistate Decision Making for Renewable Energy and Transmission: Spotlight on Colorado, New Mexico, Utah, and Wyoming (2009), *available at* http://www.nrel.gov/analysis/workshops/law_ conference_09.html.

293. *See*, *e.g*, CPUC, *Connections*, at 1, 3 (May 2009) & CPUC, *Connections*, at 1, 3-4 (Jan. 2009), *available at* http://www. dora. state.co.us/puc/publications/Connections.htm.

294. *See*, *e.g.*, 2009 NV A.B. 387 (2009); In re Solar Energy Systems Incentive Program, the Wind Energy Systems Demonstration Program, Docket No. 09-08001 (NV PSC 2009); In re Electric Utility Decoupling and Other Matters, Docket No. 09-07016 (NV PSC 2009); In re Regulations Regarding Renewable Portfolio Standards, Docket No. 09-07012 (NV PSC 2009); In re Solar Thermal Systems Demonstration Program, Docket No. 09-06033 (NV PSC 2009).

295. 2009 NV S.B. 358 (2009).

296. In re NV Energy, Docket Nos. 09-08020 & 09-08018 (NV PSC 2009); In re Nevada Power Co., Docket No. 08-12002 (NV PSC 2008).

297. In re NV Energy, Docket Nos. 09-06015, 09-04007 & 09-02005 (NV PSC 2009); In re NV Energy, Doc. 09-03-008 (NV PSC 2009); In re NV Energy, Docket Nos. 09-08015& 09-08013 (NV PSC 2009); In re NV Energy, Docket Nos. 09-05025 & 09-05023 (NV PSC 2009); In re Rocky Mountain Power, Docket Nos.

E. Oregon

Portland General Electric (PGE), one of the two state-regulated IOUs with a major presence in Oregon, received approval of a 7.3% rate increase ($121 million) in January 2009. Of particular interest in the order was the Oregon Public Utility Commission's (OPUC's) authorization to the utility to implement, on a two-year trial basis, a new "decoupling" mechanism, which would protect it from a reduction in profits due to successful conservation initiatives. The OPUC conditioned this on a slight lowering of PGE's return on equity (from 10.1% to 10.0%) to reflect the lower business risk.[298] The utility was disappointed, however, by the OPUC's direction on September 30, 2008 to refund approximately $33 million in previously collected rate revenues on the Trojan nuclear plant (which was closed in 1993). The refund order reflected the OPUC's interpretation of how to implement a court decision that found the previous collection of a return on PGE's Trojan investment to be inappropriate.[299] On the natural gas front, the sinking of the economy into recession produced at least some good news, as Northwest Natural Gas was able to accelerate, with the OPUC's approval, a $32 million credit to customers in the 2009 second quarter, as it experienced gas procurement costs substantially below the assumptions built into its existing rates.[300]

Both PGE and PacifiCorp, the other major Oregon IOU, proceeded with large-scale generation procurement programs, driven in part by escalating state renewable portfolio requirements. In early 2008, PGE issued a request for 410 MWs, consisting of 192 MW for six to ten year terms (beginning in 2010) and 218 MW specifically drawn from renewable resources – looking ahead to the state's five percent renewable portfolio standard by 2011 (twenty-five percent by 2025).[301] This RFP does *not* include a self-build benchmark or proposal.[302] PacifiCorp struggled with state regulatory approvals of its 2000 MW RFP for baseload, intermediate, and peaking resources to be available starting in 2012. The utility, which provides service in six different states, was subjected to conflicting requirements on the acceptability of coal-fired resources—with the OPUC dictating stringent restrictions on coal-fired generation[303] and the Utah Public Service Commission (UPSC) conversely conditioning its approval, in a September 25, 2008 order, on the *elimination* of bias against coal-fired power. PacifiCorp resolved the dilemma by deciding to instruct bidders to designate the state they had in mind and to include coal-fired facilities only for Utah-

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09-05029 (NV PSC 2009); In re Southwest Gas Corp., Docket No. 09-06016 (NC PSC 2009); In re Vulcan Power Co., Docket Nos. 08-12014 & 08-07017 (NV PSC 2008).

298. In re Portland General Elec. Co., Docket No. UE 197, Order 09-020 (OR PUC 2009).

299. In re Application of Portland General Electric Co. for an Investigation, Docket Nos. DR 10 UE 88, and UM 989, Order 08-487(OR PUC .2008).

300. News Release, OPUC, Commission Approves Req. to Return $32 million to NW Natural Customers (2009).

301. The Oregon RPS has variable requirements. The 5% and 20% targets are for large utilities. For detailed description, see the OPUC website, http://www.puc.state.or.us/PUC/Oregon_RPS_Summary_Oct2007.pdf (last visited Oct. 10, 2009).

302. Harriet King, *Portland General Issues Draft RFP for 410 MW*, MEGAWATT DAILY (Jan. 10, 2008).

303. Conditions included a five-year limitation on the duration of any coal-dependent bid plus indemnification (and associated security) against the risk of higher costs due to greenhouse gas regulation. *See* In re PacifiCorp, Approval of Draft 2008 RFP, Docket No. UM 1360, Order 08-310, (OPUC 2008).

designated bids.[304] Further procurement (and/or self-build) of 400 to 700 MWs of generation was put on the table by PGE for 2009 in proceedings before the OPUC.[305]

Oregon's retail choice program, which is applicable only to large industrial loads, showed some degree of attrition when, during a late November 2008 "shopping window," 160 customers decided to return to PGE – despite an impending PGE rate increase. In the prior year, the utility was close to its 300 MW cap on total load that may turn to alternative suppliers, but the drop-off in participation seen in November will leave customers with an aggregate load of 250 MW still participating.[306] In addition, PGE made strides in an aggressive campaign to install some 850,000 "smart meters" over a two-year process to be concluded in late 2010. The OPUC approved the program in a May 2008 order. The advanced meters, with a capital cost of over $130 million (but annual operating savings projected as $18 million in 2011), initially will have limited functions (i.e. remote meter-reading and activation/deactivation), but are designed to support more ambitious functions in the future (i.e. demand response and direct load-control programs).[307]

F. Texas

During 2008 & early 2009, more than sixty percent of Texas retail load in areas served by the Electric Reliability Council of Texas (ERCOT) was served by alternative energy suppliers, including more than forty percent of residential load.[308] Unlike elsewhere in the U.S., both wholesale and retail electric markets are fully regulated by the Texas Legislature and Public Utility Commission (PUCT). In early and mid-2008, wholesale market prices increased very substantially and experienced volatility due to increases in generation fuel costs, transmission congestion and unexpected generation outages. Several competitive retail electric supply providers failed and a small but significant number of customers lost beneficial fixed price supply agreements and deposits when switched to a new competitive supplier or Provider of Last Resort (POLR) service. To avoid or mitigate such experiences in the future and in response to legislation directing that it adopt uniform terms for use in retail billing, the PUCT adopted or has pending revisions to its POLR, customer disclosure, billing of retail electric services, a rule to expedite customer switch timelines and electric supplier registration rules. [309] Prices, however, had materially declined by mid-2009.

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304. *PacifiCorp seeks 2000 MW for 2012-16*, POWER MARKETS WEEK (Oct. 13, 2008).

305. Pam Radtke Russell, *PGE Eyes Adding Gas-Fired Generation*, ELECTRIC POWER DAILY (May 5, 2009).

306. Harriet King, *Many Industrial Customers Decide to Return to PGE*, POWER MARKETS WEEK (Dec. 8, 2008).

307. In re Portland General Electric Co. Advanced Metering Infrastructure, Doc. No. UE 189, Order 08-245 (OR PUC 2008).

308. PUCT, SCOPE OF COMPETITION IN ELECTRIC MARKETS IN TEXAS - REPORT TO THE 81ST TEXAS LEGISLATURE, at 43 (PUCT 2009) .

309. PUCT, *supra* note 308, at 1-2, 9-14, 43; H.B. 1822 (2009); Order Adopting Amendments to § 25.214 & § 25.474, Rulemaking to Expedite Customer Switch Timelines (PUCT 2009); Proposal for Publication of Amendment To § 25.475, Rulemaking to Implement Changes to Customer Disclosures, Docket 37214 (PUCT 2009); Proposal for Publication of Amendment To § 25.25 & § 25.479, Rulemaking to Adopt

Three areas in Texas are not served by ERCOT (i.e. which serves eighty-five percent of Texas load) and retail competition is not permitted in these areas (i.e. the service territories of Entergy Texas and El Paso and that portion of Texas served by the Southwest Power Pool (SPP)). In December 2008, studies were filed by Entergy, ERCOT and SPP as directed by the PUCT on the costs and benefits of Entergy joining one of the two transmission provider organizations. Entergy had initially proposed joining ERCOT, but the cost-effectiveness of this action has been questioned by the PUCT. The matter remains pending.[310] Also, in November 2008, ERCOT announced that the cost of implementing a nodal market design in place of the current ERCOT zonal design, including day ahead and real-time energy markets (as compared to the current balancing market) and locational marginal pricing, had approximately doubled to $660 million and that the new design would not be ready for implementation until December 2010 (as compared to the January 2009 expected date). The PUCT had directed that such a design be implemented in 2005, and issued in December 2008 an independent report indicating that the new design's development and implementation remains beneficial.[311]

Texas is also a leader in the development of wind energy, with the largest installed capacity in the U.S. (8,361 MW at December 31, 2008).[312] In mid-2008, the PUCT approved the designation of five Competitive Renewable Energy Zones and directed that studies be initiated to design and cost transmission facilities needed to collect and deliver the wind energy to Texas load centers. The five zones were defined based upon their potential for the development of large amounts of renewable, wind generation. In October, the PUCT identified the major transmission improvements necessary to implement its plan at the five zones, concluding that a total of 18,456 MW of wind generation could be obtained at a cost for transmission of $4.93 billion. In 2009, the PUCT continued implementation of this Plan with selection of transmission providers and constructors and by defining the level of committed wind generation required before transmission would be constructed.[313] The PUCT has also approved two distribution utility programs to install advanced "smart" metering, adjudicated several distribution rate cases, approved a settlement of a major enforcement action against improper market behavior and, as required by

Common Terms Used in Billing, Docket 37070 (PUCT 2009); Proposal for Publication of Amendment To § 25.361 & § 25.364, Rulemaking to Implement Requirements of PURA § 39.151(d) Concerning Decertification of an Independent Organization, Project No. 33812 (PUCT 2009) (i.e. process for decertification and replacement of ERCOT if necessary in the future); Press Release, PUCT, Electric Customer Benefits Grow (Low Income Discount Increases, Price Offers Below 10 cents/kwh) (2009) (also noting State funding for a 15% discount for low-income customers in summer 2009).

310. PUCT, *supra* note 308, at 39; Entergy Transition to Competition, Project No. 33687 (PUCT 2009), *available at* http://www.puc.state.tx.us/electric/projects/33687/33687.cfm.

311. PUCT, *supra* note 308, at 2; Press Release, ERCOT Submits Preliminary Schedule, Budget for NODAL (Nov. 26, 2008); Press Release, CRA Int'l, Update on the ERCOT NODAL Market Cost-Benefit Analysis (Dec. 18, 2008) (each is available on PUCT website).

312. *See* Press Release, American Wind Energy Assoc., Fighting Against Impact of Economic Crisis, U.S. Wind Energy Industry Installs 1,200 MW in Second Quarter (July 28, 2009).

313. PUCT, *supra* note 308, at 3, 16 &23-27; Order on PUC Staff's Petition For Designation Of Competitive Renewable Energy Zones, Docket No. 33672 (PUCT 2008); Proposal For Amendment To § 25.174, Proceeding to Establish Policy Relating to Excess Development in Competitive Renewable Energy Zones, Project No. 34577 (PUCT 2009).

legislation, has raised the energy efficiency goal (i.e. peak demand reduction) for utility programs to twenty percent by January 2010.[314]

Noting that "Texas is at a crossroads in planning its energy future", the Governor's Competitiveness Council, in July 2008, issued the 2008 Texas State Energy Plan containing thirty-seven specific recommendations for further action in development of a reliable and lowest reasonable cost electric supply for Texas.[315] Noting that "The fuel mix used to generate electricity is heavily weighted toward natural gas", the Plan notes the desirability of developing a "diverse mix of new generation". Its specific recommendations encourage continued strengthening of the competitive, retail electricity market, supporting expanded DSM and energy efficiency as a means of meeting electric service needs including smart grid approaches and encouraging further development of renewable energy.

G. Washington

The Washington Utilities and Transportation Commission (WUTC) adjudicated a series of electric and natural gas rate orders during 2008-9. Generally, net natural gas rates declined significantly as the commodity cost of gas declined while electric rates rose modestly. In light of economic conditions, Companies generally noted that projects had been delayed or costs reduced to avoid the need for more significant upward rate requests.[316] Puget Sound Energy (PSE) agreed in February 2009 to sell 2 million MWH of system power including renewable energy credits to Southern California Edison (SCE) over two years as part of an agreement to resolve litigation respecting the 2000-2001 California energy crisis. SCE requires the renewable energy to achieve RPS standards in California effective for 2010, whereas the Washington standard does not take effect to 2020. The energy sold is to be produced by two existing PSE windfarms having a capacity of 380 MW. The sale requires regulatory approval in California. PSE has also announced that it will develop with RES Americas, on a joint ownership basis, an additional large wind farm in southeastern Washington with a capacity of 1,250 MW. The Company has also announced that its Green Power Program, through which it delivers renewable energy to customers who pay an additional cost-based fee to receive specifically such energy, has delivered in 2008 twice the energy (i.e. 290,000 MWH) to its 21,000 Green Power customers than it did in 2006.[317] Also in February 2009, the acquisition of PSE by a consortium led by Macquarie Group of Australia closed. The acquisition was approved by an Order from the WUTC in December

314. PUCT, *supra* note 308, at 4, 18-23 & 27-29.

315. 2008 TEXAS STATE ENERGY PLAN, at 5-10 (2008), *available at* http://govenor.state.tx.us/files/gcc/2008_Texas _State_Energy _Plan.pdf.

316. *See, e.g.*, WUTC v. Avista Corp., Docket No. UG-090767 (WA UTC 2009); WUTC v. Northwest Natural Gas Co., Docket No. UG-090684 (WA UTC 2009); WUTC v. Avista Corp., Docket Nos. UE-080416 & UG-080417 (WA UTC 2008); WUTC v. Puget Sound Energy, Inc., Docket Nos. UE072300 & UG-072301, Order 12 (WA UTC 2008) & Order 13 (WA UTC 2009).

317. *See* Pam Russell, *Puget in Deal to Sell 2 Million MWH to SoCalEd*, ELECTRIC POWER DAILY, at 7 (Feb. 25, 2009); Harriet King, *Puget Plans Venture to Develop Wind Farm*, ELECTRIC POWER DAILY, at 5 (Dec. 16, 2008).

2008 (and earlier by FERC) imposing seventy-six conditions designed to protect ratepayer interests including continued local control of the company.[318]

318. In re Puget Holdings, Inc., Docket No. U-072375 (WA UTC 2008); Puget Energy, Inc., 123 F.E.R.C. ¶ 61,050 (2008).

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